



# **Quantification protocol for carbon dioxide capture and permanent geologic sequestration**

DRAFT

Quantification Protocol for CO<sub>2</sub> Capture and Permanent Geologic Sequestration v2.1 | Alberta Environment and Protected Areas

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## Summary of Revisions

Version	Date	Summary of Revisions
Draft 2.1	May 2026	<ul style="list-style-type: none"><li>• A definition for power purchase agreement was added under the <b>Glossary</b>.</li><li>• Requirements for <b>Removal Credits</b> under <b>section 1.6</b> have been edited.</li><li>• <b>Section 4.3.3</b> was added to provide a pathway for direct air capture projects to claim electricity generated at a low carbon intensity project if all conditions are met.</li><li>• Documentation requirements were added for Flexibility Mechanism 1 projects under <b>section 5.2</b>.</li><li>• <b>Appendix E</b> was added to provide an example of how reversal error correction accounting would be applied for a project with multiple sources injecting into the same well.</li><li>• Minor error correction and clarification edits have been made throughout.</li></ul>

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# 1.0 Emission Offset Project Description

Carbon dioxide (CO<sub>2</sub>) is emitted as a by-product in many industrial production processes and as a result of fuel combustion. This CO<sub>2</sub> may be captured for other uses or released directly to the atmosphere. Capturing CO<sub>2</sub> emissions and transferring them to a geologic storage zone(s) suitable for permanent sequestration results in a permanent reduction in CO<sub>2</sub> emissions.

Carbon capture and storage projects applicable under this protocol consist of three main components:

- a) CO<sub>2</sub> capture infrastructure, which includes a process or process modification to a facility to capture vented CO<sub>2</sub> emissions. The carbon capture facility may be separate from the emission source facility;
- b) A CO<sub>2</sub> pipeline and/or other means of transportation to transport CO<sub>2</sub> from the capture facility to the injection well(s); and
- c) Disposal of CO<sub>2</sub> through permitted sequestration wells and into a permitted geologic storage zone(s) suitable for permanent sequestration.

Emission offset project developers using this protocol should have familiarity with CO<sub>2</sub> capture and storage activities and greenhouse gas quantification methodologies.

## 1.1 Emission Offset Protocol Scope

This protocol is for quantifying the net geological sequestration of carbon dioxide that meets the requirements set out in section 19(2) of the Technology, Innovation and Emissions Reduction Regulation (TIER). The sequestration must not be subject to a carbon price outside of the federal Clean Fuel Regulations. Project activities which are in scope may include the capture of New CO<sub>2</sub>, and the compression, transport, injection, and permanent net geological sequestration of CO<sub>2</sub>. A process flow diagram for a typical carbon capture and sequestration (CCS) project is shown in Figure 1: Process Flow Diagram for the Baseline Condition.

This protocol does not apply to CCS activities using CO<sub>2</sub> enhanced oil recovery (EOR), or acid gas injection schemes associated with sour natural gas processing operations. Emission offset project developers with CO<sub>2</sub> EOR projects should refer to the most current Quantification Protocol for Enhanced Oil Recovery.

### Protocol Approach

This protocol applies to CCS emission offset projects where captured CO<sub>2</sub> is received from a regulated facility under TIER, which would otherwise have been emitted to atmosphere and under the project condition is injected into an approved D065 CO<sub>2</sub> sequestration scheme approval. This protocol provides the methodology for emission offset project developers to follow, and outlines the requirements for measurement, monitoring, quantification, reporting and verification of net geological sequestration. Under the TIER regulation compliance reporting requirements, a TIER regulated facility must report the captured CO<sub>2</sub> as part of their Total Regulated Emissions (TRE).

### Baseline Condition

Baseline emissions are determined using a projection-based baseline to quantify the emissions that would have otherwise been emitted to the atmosphere in the absence of the offset project. The baseline emissions are quantified using the metered quantity of CO<sub>2</sub> injected into the targeted geologic storage zone(s) suitable for permanent storage less any CO<sub>2</sub> injected that originates from within the project boundary. Baseline sources and sinks are shown in Figure 2: Baseline Sources and Sinks.

The only greenhouse gas eligible under the baseline condition of this protocol is CO<sub>2</sub>. The sequestration of methane (CH<sub>4</sub>) or nitrous oxide (N<sub>2</sub>O) is not eligible for emission offsets.

### Project Condition

Project emissions may include those from the CO<sub>2</sub> capture, compression, transport, and injection activities associated with injecting CO<sub>2</sub> into a targeted geologic storage zone(s) for permanent sequestration. In addition, any potential CO<sub>2</sub> reversal from the storage formation must be accounted for, as per the monitoring and quantification requirements outlined in this

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protocol. A wide range of light hydrocarbons and/or sulfur-based gases may also be emitted as a result of CO<sub>2</sub> capture, compression, transport, and injection. CCS projects primarily sequester CO<sub>2</sub>. However, the CO<sub>2</sub> stream may include several impurities such as CH<sub>4</sub>, N<sub>2</sub>O, H<sub>2</sub>S, N<sub>2</sub>, etc.

Some of the impurities may be greenhouse gases other than CO<sub>2</sub>. The greenhouse gases that must be included in the project condition include all related emissions of CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O, as per the quantification section of this protocol. The protocol does not require quantification of other impurities. Credit generation is only possible for CO<sub>2</sub>.

A project must use the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports for the associated global warming potential of these gases.

### **Emission Offset Project Developer**

The CO<sub>2</sub> capture, compression, transport and net geological sequestration may or may not be conducted by the emission offset project developer. It is likely that different entities may conduct each of the project activities. Each entity must maintain records in accordance with 5.3 Record Keeping and Project Archives. Records must be available for verification or reverification of the emission offset project and must also be made available to any third-party assurance provider fulfilling a required verification under TIER.

The emission offset project developer as described in TIER is accountable for the project meeting the requirements of both TIER and the Standard for Greenhouse Gas Emission Offset Project Developers (the Standard). It is the emission offset project developer's responsibility to work with all entities conducting a portion of the project activities to obtain access to all records, data and equipment that may be required for monitoring, measurement, quantification and verification of an emission offset claim. The emission offset project developer must also retain all project records according to the requirements in TIER, the Standard and this protocol.

### **CO<sub>2</sub> Capture Entity**

The CO<sub>2</sub> capture entity is responsible for the equipment and is the originator of data records related to CO<sub>2</sub> capture that may be required for GHG emissions quantification, reporting and verification. The data records may include evidence of captured CO<sub>2</sub> quantities, including concentration and composition, and of any heat, power or fuel used on-site for CO<sub>2</sub> capture. The capture entity may also be the owner of compression equipment and responsible for all records related to compression for quantification and verification.

### **Transport Entity**

The transport entity is responsible for the equipment and is the originator of data records related to CO<sub>2</sub> compression and transportation that may be required for GHG emissions quantification, reporting and verification. This may include evidence of delivered CO<sub>2</sub> quantities, including concentration and composition and of any heat, power or fuel used on-site or fuel used to transport CO<sub>2</sub>.

This protocol provides a methodology for the quantification of greenhouse gas emissions associated with pipeline or vehicle transport. Transportation of CO<sub>2</sub> via mechanisms other than pipeline or truck can apply through the approval of a deviation request from the Director, Emission Offsets. The request must outline how all emissions associated with the transport system will be measured and quantified.

### **Sequestration Entity**

The sequestration entity is responsible for the equipment and is the originator of data records related to CO<sub>2</sub> injection, as well as monitoring data and any GHG emissions (downstream of the injection meter) that may be required for quantification, reporting and verification. This will include evidence of injected gas CO<sub>2</sub> composition, injected CO<sub>2</sub> quantities, and records for any heat, power or fuel used on-site.

## **1.2 Offset Crediting Period**

The offset crediting period for this activity is 20 years, with the possibility of ongoing five-year extensions. The criteria for project extension, is set out in the Standard for Greenhouse Gas Emission Offset Project Developers.

The reporting periods must be contiguous for the duration of the offset crediting period and any reversals, or negative GHG emission statements must be reported.

### 1.3 Protocol Applicability

Emission offset project developers must be able to demonstrate that the emission offset project meets the requirements of the Alberta emission offset system, TIER, this quantification protocol, the Carbon Offset Emission Factors Handbook, and other related Standards and guidance documents.

The emission offset project developer must obtain a Director approval letter prior to project creation on the Alberta Emission Offset Registry, which may be granted if the Director is satisfied the project has ensured the project boundary, CO<sub>2</sub> source, and eligibility requirements will be met. The emission offset project developer's written submission requesting the Director's approval must provide evidence demonstrating the project meets the following requirements and include:

1. An explanation of the emission offset project activity, a description of the overall scope, how the project meets all applicability criteria in this section, any flexibility mechanism to be utilized, any plan for alternate sequestration or transfers of the CO<sub>2</sub> outside of the project boundary, and an explanation of any special conditions that may apply to the project activity.
2. The emission offset project developer demonstrates the CO<sub>2</sub> is captured from a regulated facility under TIER unless otherwise approved by the Director. This is demonstrated by actual CCS project schematics and by compliance with the measurement requirements set forth in the quantification section of this protocol.
3. The CCS scheme must have obtained approval from the Alberta Energy Regulator (AER) under Directive 065 – Resources Applications for Conventional Oil and Gas Reservoirs and Section 39 of the Oil and Gas Conservation Act, and meet the requirements outlined under Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging and Testing Requirements.
4. The emission offset project boundary must be clearly described, including CO<sub>2</sub> sources and if they are inside or outside the project boundary, the transportation system, the targeted geologic storage zone(s) and the surface locations. A clear delineation of where any regulated facility stops and the emission offset project starts must be part of the description.

The physical boundary for injection/capture will be equivalent to the boundary set out in the D065 CO<sub>2</sub> sequestration scheme approval. The emission offset project boundary includes:

- a. One or more D065 CO<sub>2</sub> Sequestration Scheme approval (outlining the part of the project boundary corresponding to the injection/sequestration entity), and the approved targeted geologic storage zone(s); and
  - b. The capture and transportation elements of the project unless the associated emissions are accounted for by the regulated facility from which the CO<sub>2</sub> is being captured.
5. The project must obtain all required operating permits under relevant regulations in Alberta prior to emission offset project creation on the registry.
  6. The net geological sequestration or storage from the project must be quantified using actual measurements and monitoring as indicated in this protocol.
  7. The emission offset project developer must provide confirmation of whether or not the project has any special conditions to the Director. These will require further details to be provided to the Director in order to obtain emission offset project approval, and include (but are not limited to):
    - a. Projects that employ alternate technologies for CO<sub>2</sub> capture, transport, injection, or use technologies and processes other than those commercially available and outlined in this protocol.

If the proposed emission offset project meets all requirements of the Protocol, the Standard for Greenhouse Gas Emission Offset project developers and TIER, the Director will grant timely approval. This written request can be submitted after the requirements above are met and prior to the submission of the initial project plan to the registry.

### 1.4 Flexibility Mechanisms

This protocol provides the following flexibility mechanisms for an emission offset project developer. Any usage of a flexibility mechanism must be documented in the offset project plan or the offset project report and project plan with justification and rationale for the flexibility mechanisms used. A clear explanation of the flexibility mechanism and alignment with the protocol

quantification must be demonstrated and be verifiable. Proponents are referred to the most recent version of the Standard for Greenhouse Gas Emission Offset Project Developers for information regarding deviations from protocols.

#### **1.4.1 Flexibility Mechanism 1: Direct Air Capture Facility as Emissions Source**

This flexibility mechanism allows project developers to source CO<sub>2</sub> from direct air capture (DAC) facilities in Alberta. Any DAC facility not located at a regulated facility will be included within the project boundary and DAC sourced CO<sub>2</sub> under this flexibility mechanism is not required to come from a regulated facility under TIER. Project developers must notify the Director of their intent to utilize a DAC source, provide the details of the source facility and the expected quantity of CO<sub>2</sub> to be captured per year. Project developers using this source of CO<sub>2</sub> must quantify all emissions upstream of the injection meters except for emissions of the captured CO<sub>2</sub>. Applicable material inputs/consumable must also be considered during quantification. The quantification must meet the same rigor as regulated facilities, as outlined in the TIER Alberta Quantification Methodology. The baseline will be determined by the metered tonnes of CO<sub>2e</sub> captured directly from the atmosphere and injected.

Under Flexibility Mechanism 1, eligible DAC projects may use the quantification methodology for P8 Off-Site Electricity Generation under section 4.3.3 P8 Off-Site Electricity Generation Quantification Methodology for Flexibility Mechanism 1 Projects for offsite electricity generation from a low carbon intensity electricity generation facility. All requirements under section 4.3.3 P8 Off-Site Electricity Generation Quantification Methodology for Flexibility Mechanism 1 Projects must be met in order to do so.

#### **1.4.2 Flexibility Mechanism 2: Project Boundaries**

Where the project boundaries differ from the process flow diagram for the project condition (see Figure 3: Process Flow Diagram for the Project Condition), the differences must be outlined and addressed in the Director approval requested prior to project initiation on the registry. This ensures all direct and indirect emissions associated with the offset project are accounted for in the offset project plan or the compliance reporting for the associated TIER facility as intended to account for all emission sources. Proponents are referred to the most recent version of Standard for Greenhouse Gas Emission Offset Project Developers for information regarding deviations from protocols.

#### **1.4.3 Flexibility Mechanism 3: Limiting Impact of Reversals to TIER Credits Through Increased Discount Factor**

If a project developer elects to limit the reversal true-up liability for the crediting and post crediting pre-closure project stages to a maximum total of three-year injected volume based on the average annual injection up to the last reporting period over the course of the crediting period(s), they can elect to apply an increased discount factor.

The maximum liability is calculated as the average annual volume of CO<sub>2</sub> injected (B1), calculated from project initiation to the last verified reporting period, multiplied by three years. Under this flexibility mechanism project developers are still required to apply the discount factor to injected CO<sub>2</sub> (B1) outlined in section 1.5.3 Post-Closure Reversal to cover post-closure reversals from the first day of the initial project reporting period to the end of year three. Beginning in year four, the applied discount factor will increase to 0.01 and will be discounted on all tonnes injected (B1) during the crediting period(s).

Discounted injected CO<sub>2</sub> is documented and verified in each offset project report and will be accounted for as 'retired to atmosphere' by the Government of Alberta.

Project developers must notify the Director of their intention to apply flexibility mechanism 3 to their project in their written request submitted as per section 1.3 **Protocol Applicability**. A project must apply this flexibility mechanism from project initiation onward. Once the initial project plan has been submitted to the Alberta Emission Offset System Registry, the project can no longer apply this flexibility mechanism.

If a project has applied flexibility mechanism 3 and wishes to opt-out of this flexibility after the initial project plan is submitted, they are permitted to do so, but all collected volumes from the applied discount factor will be forfeited.

In the event the project developer is not the sequestration entity, there may be scenarios where some injected volumes are opted-in to flexibility mechanism 3 and others are not. It is the project developer's responsibility to ensure volumes are tracked accordingly to facilitate the application of this mechanism.

#### 1.4.4 Flexibility Mechanism 4: Tenure Mechanism Without Liability Transfer

In some cases, CCS project developers may be granted sequestration rights from the Ministry of Energy and Minerals through a tenure mechanism that does not permit the transfer of liability under the *Mines and Minerals Act* through the issuance of a closure certificate. While this does not preclude an emission offset project from generating emission offsets under this protocol, the project developer must receive written approval from the Director and adhere to the following conditions:

- Apply flexibility mechanism 3 in section 1.4.3 Flexibility Mechanism 3: Limiting Impact of Reversals to TIER Credits Through Increased Discount Factor to their projects throughout their crediting period(s). This includes both the liability limitation and application of the increased discount factor beginning in year four.
- No further true-up liability obligations associated with TIER climate liability will be required when the project developer can demonstrate the following:
  - a. Evidence is provided to the Director that all project wells associated with the emission offset project have been abandoned in accordance with applicable well abandonment regulations, directives, and rules;
  - b. 20 years have passed since the date the last project well was abandoned; and
  - c. A post-crediting, pre-closure reversal as defined in 1.5 Reversals has not occurred since the last well was abandoned.

For projects utilizing this flexibility mechanism, in lieu of closure certificate issuance, the conditions for post-closure liability transfer will be used to differentiate between project life cycle stages as they relate to a reversal under section 1.5

### Reversals.

## 1.5 Reversals

This protocol defines a reversal as an accidental release of CO<sub>2</sub> from the targeted geologic storage zone(s) during or after the offset crediting period that meets all of the following criteria:

1. The AER determines a loss of containment has occurred under the emission offset project's D065 CO<sub>2</sub> sequestration scheme approval;
2. The loss of containment cannot be remedied; and
3. An expert investigation determines the quantity of CO<sub>2</sub> that is subject of the loss of containment which will reasonably leak into the atmosphere within 100 years of the occurrence of the loss of containment.

Note that venting or removal of CO<sub>2</sub> after the injection meter through the injection well which is not accounted for during an offset crediting period would also be considered a reversal.

The timing of a reversal will determine how the reversal is accounted for as per sections 1.5.1 Negative Greenhouse Gas Statement, 1.5.2 Post-Crediting, Pre-Closure Certificate Reversal and 1.5.3 Post-Closure Reversal. Distinct time frames for reversals are considered as follows.

- Net Reversal – A reversal that occurs during any offset reporting period and results in a negative greenhouse gas statement.
- Post-Crediting, Pre-Closure Certificate Reversal – A reversal that occurs after the end of the offset crediting period, but prior to the issuance of a closure certificate.
- Post-closure Reversal – A reversal that occurs after a closure certificate has been granted to the project developer by the Crown.

True-up processes will consider the last emissions injected, to be the first emissions released as part of a reversal. In cases where multiple emission offset projects are injecting into shared pore space:

- The impacted sequestration reservoir will be the approved targeted geologic zone(s) as identified in the sequestration tenure agreement and the D065 CO<sub>2</sub> sequestration scheme approval, and
- the last-in first-out accounting will be applied, causing the reversal to be apportioned to the appropriate offset projects until it is fully accounted for.

When the reversal is identified, the last-in first out principle will be applied to ensure the entire reversed amount is accounted for and allocated to individual project serial ranges. Once the impacted emission offsets are identified and apportioned to particular serial ranges of individual emission offset projects through the last-in first-out principle, the error correction process under section 5.3.2 of the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports will be applied.

For projects utilizing 1.4.4 Flexibility Mechanism 4: Tenure Mechanism Without Liability Transfer, in lieu of closure certificate issuance, the conditions for post-closure liability transfer will be used to differentiate between project life cycle stages as they relate to a reversal.

Materiality thresholds do not apply to error correction volumes associated with a reversal.

Project developers shall not require true-up action under section 1.5 **Reversals** of this protocol in the event of a loss of containment of CO<sub>2</sub> if the project developer provides empirical evidence satisfactory to the Director demonstrating that the loss of containment was the result of an event unrelated to the selection, operation, or maintenance of the targeted geological zone(s) and associated injection infrastructure other than trespass into the targeted geological zone(s). Examples include a natural disaster or terrorist attack.

### 1.5.1 Negative Greenhouse Gas Statement

A negative greenhouse gas statement occurs when project emissions are greater than baseline emissions during any reporting period, resulting in a negative greenhouse gas statement in the project report. Section 1.5.1.1 *Net reversal* provides information about when the cause of the negative greenhouse gas statement is due to a reversal (under P20). However, a negative statement may also occur for other reasons, such as where project emissions are greater than net reductions due to a low volume of injected CO<sub>2</sub> during a reporting period. Project emissions for fugitive and venting from the capture, transport and injection of CO<sub>2</sub> are quantified through the existing sources outlined in section 3.0 Project Condition of this protocol, such as:

- P18 - Venting of CO<sub>2</sub> at Injection Well Sites
- P19 - Fugitive Emissions at Injection Well Sites
- P23 - Emissions from Truck Transport

Once the offset project report with a negative statement is verified and submitted to the Registry, the project developer must notify the director of the negative statement and a total number of invalid emission offsets must be removed from any previous reporting period for the project by following the error correction process set out in the Standard for Greenhouse Gas Emission Offset Project Developers. If any emission offsets that are removed were used to meet a compliance obligation, the regulated facility must follow the true-up process set out in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

The reporting periods must be contiguous for the duration of the offset crediting period.

#### 1.5.1.1 *Net reversal*

A net reversal occurs when project emissions are greater than baseline emissions during any reporting period due to emissions associated with a reversal of CO<sub>2</sub> from the permitted geologic storage zone(s) resulting in a negative greenhouse gas statement. Emissions from a reversal must be quantified under P20 - Emissions from a Reversal in any reporting period according to the methods outlined in this quantification protocol. If there is a reversal event that occurs during the reporting period and emissions from P20 result in a negative greenhouse gas statement this is considered a net reversal and must be verified and reported by the project.

Once the offset project report with a negative statement is verified and submitted to the Registry, the project developer must notify the director of the negative statement and a total number of invalid emission offsets must be removed from any previous reporting period for the project by following the error correction process set out in the Standard for Greenhouse Gas Emission Offset Project Developers. If any emission offsets that are removed were used to meet a compliance obligation, the regulated facility must follow the true-up process set out in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

### 1.5.2 Post-Crediting, Pre-Closure Certificate Reversal

If a reversal occurs after the end of the offset crediting period, but prior to closure certificate issuance, it will be considered a post-crediting, pre-closure certificate reversal. During the closure period, the emission offset project developer will not be submitting regular offset reports. To ensure the department continues to have assurance of containment, the emission offset project developer of a project must submit an annual containment assurance report to the Director. A containment assurance

report template is provided in Appendix C: **Carbon Capture and Sequestration Containment Assurance Report Template** and must be used to report post-crediting status by the project developer.

Reversals of carbon dioxide during the post-crediting, pre-closure period must be reported on the containment assurance report and will result in the Director cancelling invalid emission offsets in the amount of the reversal within the project. If any emission offsets that are invalid were used to meet a compliance obligation, the regulated facility must follow the true-up process set out in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

An example of how reversal error correction accounting would be applied for a project with multiple sources injecting into the same well can be found in Appendix E: Reversal Error Correction Accounting.

### 1.5.3 Post-Closure Reversal

Once a closure certificate has been issued, the risk for a reversal is considered to be low. To mitigate the potential minimal risk or uncertainty associated with a post-closure reversal, the emission offset project developer is required to apply a reversal risk discount factor of 0.005 to injected CO<sub>2</sub> (B1) during the quantification of each greenhouse gas statement during the offset crediting period. This discount factor is applied to each offset project report, and is calculated based on injected CO<sub>2</sub>, verified and considered 'retired to the atmosphere' by the Government of Alberta.

If a post-closure reversal occurs, the Director will not initiate the cancellation of emission offsets for the project related to the post-closure reversal, and no further action is required from the project developer or regulated facility who used any of the emission offsets for compliance purposes.

## 1.6 Removal Credits

A removal or sequestration activity involves a removal of CO<sub>2</sub> from the atmosphere that would have otherwise remained in the atmosphere. Under this protocol, the net CO<sub>2</sub> captured from a direct air capture facility (under flexibility mechanism 1) or the net CO<sub>2</sub> captured from a biogenic source that is permanently sequestered in a targeted geologic storage zone(s) capable of permanent storage, may be reclassified as a CO<sub>2</sub> removal credit on the Alberta Emission Offset Registry.

The emission offset project developer must state their intent to label removal credits by written request to the Director, under 1.3 Protocol Applicability requirement 1 and document in the offset project plan or offset project report and obtain independent verification of how they have met, or will meet, the following requirements:

1. The project must capture CO<sub>2</sub> from a direct air capture facility or capture biogenic CO<sub>2</sub> (i.e., biomass energy with CCS).
2. For biogenic CO<sub>2</sub>, the project must determine the biogenic portion of the CO<sub>2</sub> emissions using Method B or Method C of the ASTM D6866 "Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis". Facilities are free to conduct analyses at a greater frequency than listed below if they choose. Facilities that are using fuel base assessment or analysis may apply to the Director for a deviation to use that method for this purpose.
  - a. Analysis must occur at least once every three months if the biogenic CO<sub>2</sub> is within a mixed stream at the point of metering upstream of co-mingling.
  - b. Analysis must occur at least once every two years if the biogenic CO<sub>2</sub> is not within a mixed stream at the point of metering upstream of co-mingling.
3. Allocate total emission offsets between removal and non-removal types using a weighted average of the composition analysis outlined in each verified offset project report.

4. A verifier must confirm assertions of claimed emissions reductions associated with the generation of removal credits and non-removal credits in their verification report that matches the offset project report. In the event of any discrepancies between the offset project report and verification report (or verification finding), no emission offsets will be able to be reclassified to removal credits for that reporting period.

CO<sub>2</sub> removal credit types on the Alberta Emission Offset Registry will carry no additional compliance benefit and are subject to all requirements and restrictions of an emission offset under TIER.

## 1.7 Glossary of Terms

Alberta Electricity Grid	A system of conductors and other equipment through which electrical energy is transmitted and distributed throughout the province. This electricity grid is an interconnected network of high voltage transmission and lower voltage distribution for delivering electricity from suppliers (generators) to consumers across the province.
Alberta Energy Regulator (AER)	The agency of the Government of Alberta that regulates the safe, responsible and efficient development of Alberta's energy resources (oil, natural gas, oil sands, coal), pipelines and subsurface sequestration activities.
Capture Site	The point in the process where gas containing CO <sub>2</sub> that would otherwise be emitted, or ambient CO <sub>2</sub> is separated and captured for eventual injection as part of a D065 CO <sub>2</sub> sequestration scheme approval.
Closure Certificate	Closure certificate as defined in the <i>Mines and Minerals Act</i> .
Closure Period	For the purposes of this protocol, the closure period is the period of time between the end of the emission offset crediting period and the issuance of a closure certificate.  For projects with a tenure mechanism that does not permit the issuance of a closure certificate, the closure period is the period of time between the end of the emission offset crediting period and all conditions under Flexibility Mechanism 4 being met.
Containment Assurance	Demonstration that the features and geologic structures relied on for the CO <sub>2</sub> sequestration activity are adequate to provide safe, long-term containment of CO <sub>2</sub> .
Custody transfer	A metering point where a fluid is being measured for transfer from one party to another, or from one emission offset project entity (capture, transportation, sequestration) to another. All metering requirements must be met as outlined in the protocol and Appendix A.
Directive 007	<i>Volumetric and Infrastructure Requirements</i> . This directive sets out the Alberta Energy Regulator's requirements for reporting volumetric data and well status changes using Canada's Petroleum Information Network (Petrinex), and prescribes the manner in which data must be submitted. Referenced to as D007.
Directive 017	<i>Measurement Requirements for Oil and Gas Operations</i> . This directive clarifies, consolidates and updates the Alberta Energy Regulator's requirements for measurement points used for accounting and reporting purposes, as well as those measurement points required for upstream petroleum facilities and some downstream pipeline operations under existing

regulations. The directive does not include instructions on how the volumes must be reported to the Alberta Energy Regulator (see Directive 007). Referenced to as D017.

Directive 020	<i>Well Abandonment</i> . This directive details the minimum requirements for abandonments, casing removal, zonal abandonments and plug backs as required under Sections 3.013 of the Oil and Gas Conservation Regulations. Referenced to as D020.
Directive 051	<i>Injection and Disposal Wells: Well Classifications, Completion, Logging, and Testing Requirements</i> . This directive classifies injection and disposal wells according to the injected or disposed fluid and specifies design, operating, and monitoring requirements for each class of well. Referenced as D051.
Directive 065	<i>Resources Applications for Oil and Gas Reservoirs</i> . This directive details the process to apply to the Alberta Energy Regulator for all necessary approvals to establish the strategy and plan to deplete a hydrocarbon pool or portion of a pool using one resource application or to operate a sequestration scheme. Referenced as D065.
Directives	Documents setting out new or amended requirements or processes to be implemented and followed by licensees, permittees and other approval holders under the jurisdiction of the Alberta Energy Regulator.
Discount factor (Df)	To mitigate remaining risk or uncertainty with post-closure reversal, the emission offset project developer is required to apply a discount factor to injected CO <sub>2</sub> (B1) during the quantification of each greenhouse gas statement during the crediting period. This discount is applied to the injected CO <sub>2</sub> and considered 'retired to the atmosphere'.
Global Warming Potential (GWP)	Measures a GHG's relative warming effect on the Earth's atmosphere compared with carbon dioxide and is often expressed as a 100-year average. The department currently utilizes the global warming potential value published in the International Panel on Climate Change Fourth Assessment Report for the gases regulated under the Regulation, consistent with the National Inventory Report prepared by Environment and Climate Change Canada.
Higher Heating Value (HHV)	The amount of heat released during the combustion of a fuel and includes the latent heat in the water produced through combustion.
Injection Meter	Meter used for quantifying injected CO <sub>2</sub> . This is expected to be a custody transfer meter as close as possible to the injection wellheads.
Regulated Facility	A facility subject to TIER, as large emitter or opted-in facility. Emissions are accounted for and verified on an annual basis.
New CO <sub>2</sub>	Anthropogenic CO <sub>2</sub> recently captured and not previously injected into a reservoir and recycled (including CO <sub>2</sub> from biomass use), or recently captured CO <sub>2</sub> from a direct air capture facility. Must not have previously been credited for sequestration.
Permanent Storage/Net Geological Sequestration	The isolation of CO <sub>2</sub> in subsurface formations. Injected CO <sub>2</sub> is trapped through mechanisms outlined in 3.0 Project Condition.

Physical System	A collection of usually linearly connected equipment and pipe and supporting utilities, etc. that would support the capture, transport and sequestration of CO <sub>2</sub> . Would not include infrastructure within any regulated facility. A physical system may support 0 or more offset projects within TIER or voluntary systems. An individual offset project may utilize all or only a portion of the physical system.
Power Purchase Agreement (PPA)	A contract to buy power over a period of time at a negotiated price from a specific facility, usually one that is on the same power grid that is used by the project requiring electricity.
Priced emissions	Emission reductions that are subject to a carbon price. Priced emissions reductions are not eligible for the generations of emission offsets under TIER.
Process Element	Components of the baseline or project that illustrate the flow of CO <sub>2</sub> but are not the sources or sinks included in the quantification of baseline and project emissions.
Project Developer	Emission offset project developer as defined under TIER.
GHG Reservoir	Component, other than the atmosphere, that has the capacity to accumulate greenhouse gases, and to store and release them. [Source: ISO 14064-2:2019]
GHG Sink	Process that removes a greenhouse gas from the atmosphere. [Source: ISO 14064-2:2019]
GHG Source	Process that releases a greenhouse gas into the atmosphere [Source: ISO 14064-2:2019]
Removal	A removal activity involves a removal of CO <sub>2</sub> from the atmosphere.
SSR	Source, sink and reservoirs, as defined above.
Targeted Geologic Storage Zone(s)	The targeted geological formation(s) that contribute to providing secure long-term sequestration of CO <sub>2</sub> as outlined in the D065 CO <sub>2</sub> sequestration scheme approval. It may include one or more seals and one or more zones that have the potential to accept sequestered CO <sub>2</sub> .
Trap	Any feature or mechanism that alone or in combination provides a low-permeability confining geologic layer (cap rock or seal). This includes mechanisms for storage in the pore spaces of the targeted zone(s) (physical, stratigraphic, or structural trapping), by capillary pressure from the water in the pore spaces between the rock (residual trapping), by dissolution in the in situ formation fluids (solubility), by hydrodynamic trapping, by adsorption onto organic matter or by reacting in geologic formations to produce minerals (geochemical trapping). [adapted from ISO 14064-2:2019]

## 2.0 Baseline Condition

The baseline scenario applicable to this protocol is assessed as projection-based. It assumes the continued practice of emitting CO<sub>2</sub> to the atmosphere from a regulated facility. Baseline emissions are projected using the quantity of CO<sub>2</sub> measured directly upstream of the injection wellheads less any injected CO<sub>2</sub> that originated within the offset project boundary. These emissions are assessed dynamically and comprise a portion of the total emissions from the emissions source. This dynamic baseline ensures that variation in CO<sub>2</sub> that is captured and injected in the project condition is accounted for and is project specific based on the project activity.

### 2.1 Identification of Baseline Sources and Sinks

The identification of sources, sinks and reservoirs (SSRs) in the baseline condition is based on ISO 14064-2: Specification, with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements. SSRs are determined to be either controlled, related or affected by the project activity and are defined as follows:

**Controlled:** The behaviour or operation of a controlled source and/or sink is under the direction and influence of an emission offset project developer through financial, policy, management or other instruments.

**Related:** A related source and/or sink has material and/or energy flows into, out of or within a project but is not under the control of the emission offset project developer.

**Affected:** An affected source and/or sink is influenced by the project activity through changes in market demand or supply for products or services associated with the project.

All SSRs were identified by reviewing the relevant process flow diagrams, consulting with technical experts and reviewing best practice guidance. This iterative process confirmed that SSRs in the process flow diagrams covered the full scope of activities under this protocol.

Based on the process flow diagram provided in Figure 1, the baseline SSRs were organized into life cycle categories and depicted in Figure 2. A description of each SSR and its classification as controlled, related or affected is provided in Table 1 and a description of each source sink is included in Table 2.

Figure 1: Process Flow Diagram for the Baseline Condition

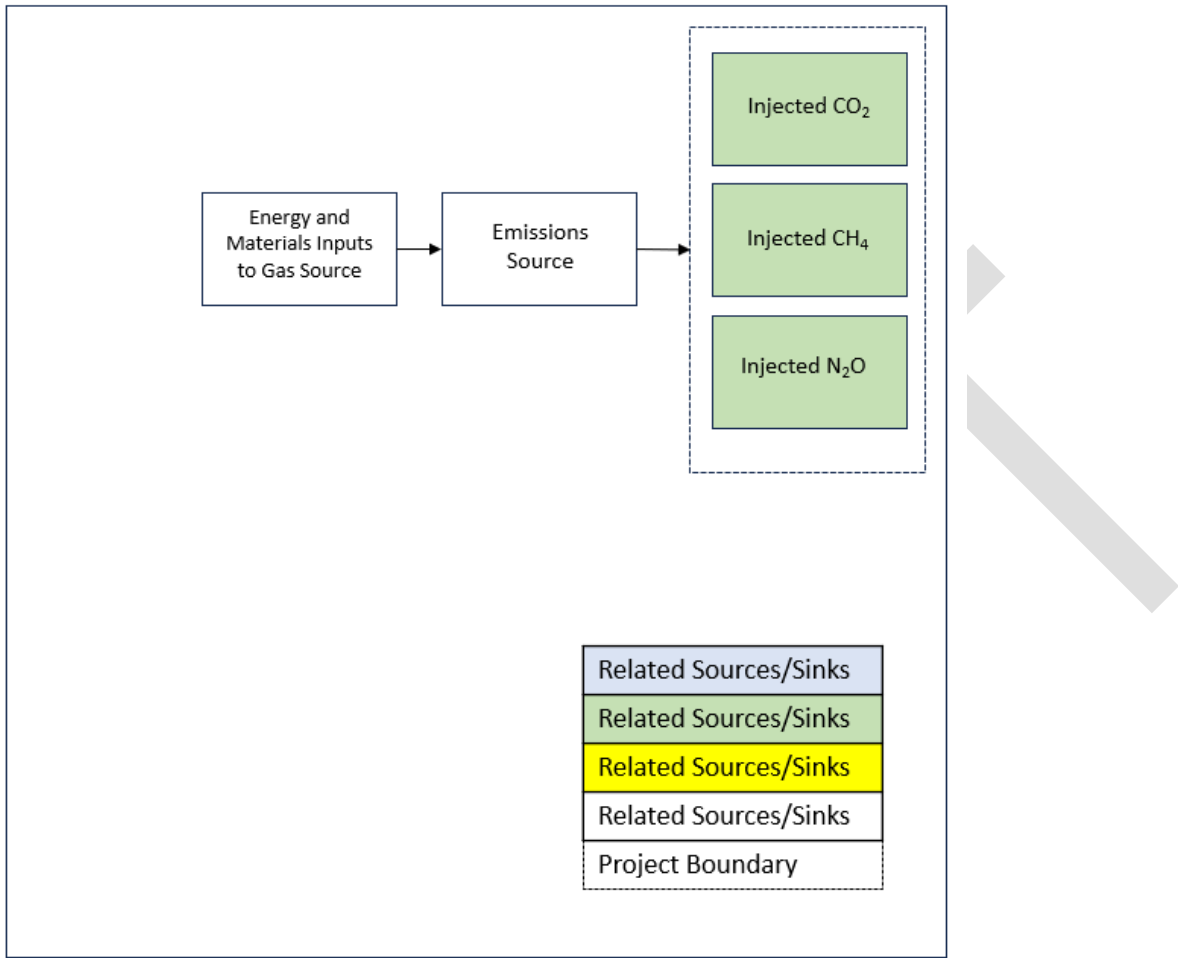
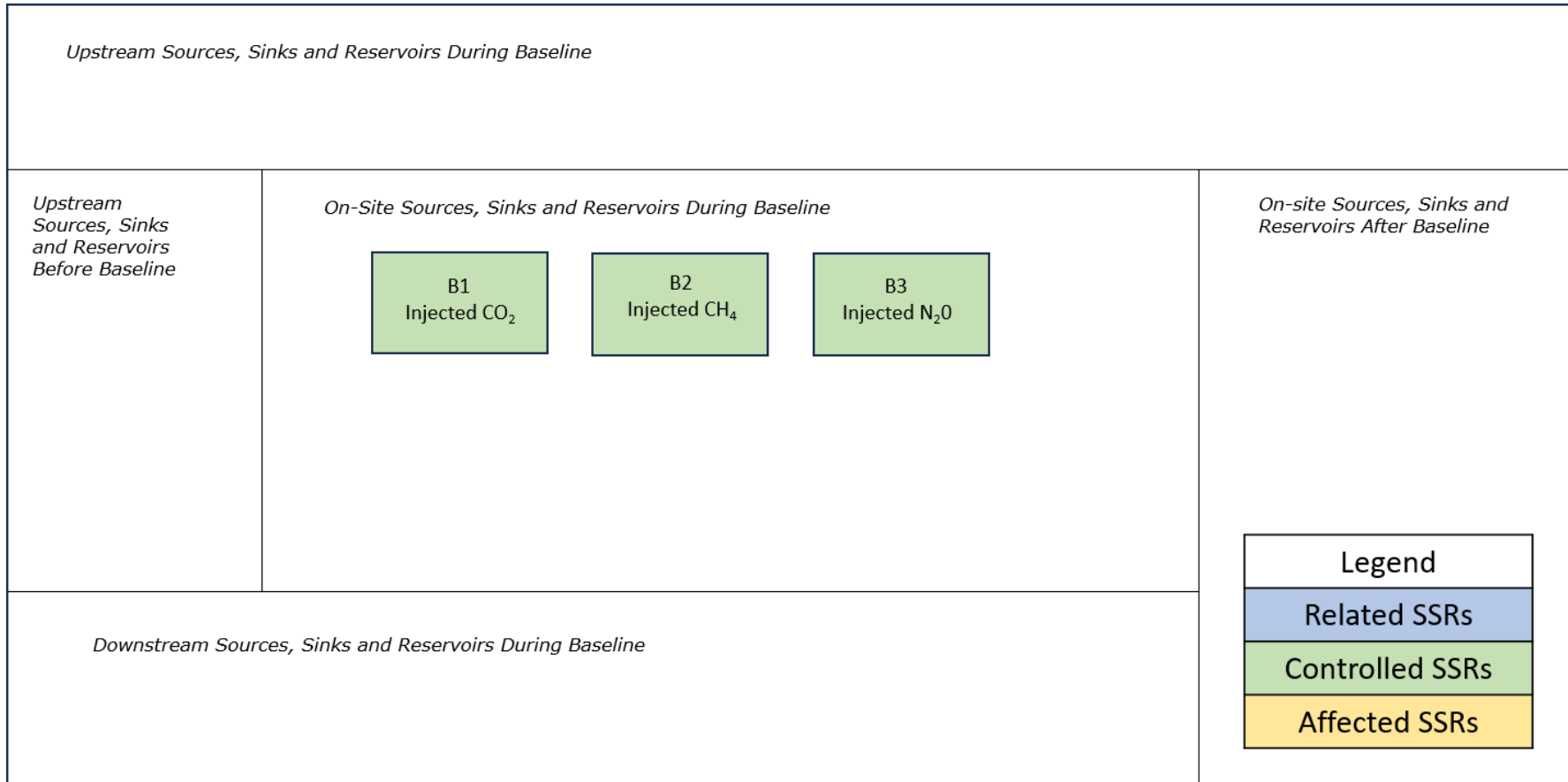


Table 1: Baseline Process Elements

Process Element	Description
Energy and Material Inputs to Gas Source	Energy and material inputs to the gas source require inputs such as electricity, heat and fuel, which may be supplied from on-site or off-site sources. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Emissions Source	The emissions source includes any type of process that generates CO <sub>2</sub> -rich gas from a GHG regulated facility in Alberta. Process elements are included for illustrative purposes only, and they do not affect the quantification.

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**Figure 2: Baseline Sources and Sinks**



**Table 2: Baseline Sources and Sinks**

Source/Sinks	Description	Controlled, Related or Affected
<i>Upstream Source/Sinks During Baseline Operation – Not Applicable</i>		
<i>On-Site Sources and Sinks During Baseline</i>		
B1 Injected CO <sub>2</sub>	<p>All CO<sub>2</sub> emissions released to the atmosphere in baseline, as projected from the project condition.</p> <p>Baseline emissions are projected using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.</p>	Controlled
B2 Injected CH <sub>4</sub>	<p>All CH<sub>4</sub> emissions released to the atmosphere in baseline, as projected from the project condition.</p> <p>Baseline emissions are projected using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.</p>	Controlled
B3 Injected N <sub>2</sub> O	<p>All N<sub>2</sub>O emissions released to the atmosphere in baseline, as projected from the project condition.</p> <p>Baseline emissions are projected using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.</p>	Controlled
<i>Downstream Sources and Sinks During Baseline – Not Applicable</i>		
<i>Downstream Sources and Sinks After Baseline – Not Applicable</i>		

## 3.0 Project Condition

Carbon capture and storage projects generally consist of three distinct components: the capture and compression of CO<sub>2</sub>; the transport of CO<sub>2</sub> to the injection wells; and the metering and disposal of CO<sub>2</sub> through injection wells and into a targeted geologic storage zone(s) suitable for permanent sequestration.

The main process elements of a typical carbon capture and storage project are described below. Carbon capture and storage projects may employ other CO<sub>2</sub> capture, transport, disposal technologies, and processes. Flexibility to accommodate these different approaches may be approved by the Director, Emission Offsets through a deviation request.

Approval from the Director, Emission Offsets is required for all new emission offset projects and includes any deviations from this protocol. If the emission offset project scenario changes, for example to include new capture sites, the project developer must update the offset project plan to document the change in project scenario.

### CO<sub>2</sub> Capture and Compression

For this protocol, only New CO<sub>2</sub> reported as exported from a regulated facility that is ultimately captured is eligible. CO<sub>2</sub> capture refers to the process of capturing CO<sub>2</sub>, and often includes the separation of CO<sub>2</sub> from other gas species generated at the emissions source. All CO<sub>2</sub> capture technologies are eligible under this protocol. The typical CO<sub>2</sub> capture infrastructure consists of the following main process blocks.

- CO<sub>2</sub> capture from existing high purity process streams, e.g., fertilizer plant, gasification;
- CO<sub>2</sub> separation. This typically includes amine solvents, absorbers and associated equipment; and/or, solvent regeneration unit(s), which may include the following:
  - Stripper column and associated reboiler, pumps and heat exchangers;
  - Solvent filtration;
  - Solvent storage;
  - CO<sub>2</sub> vent stack; and
- CO<sub>2</sub> compression, which may include a multi-stage compressor with an electrical motor and interstage coolers and knockout drums, CO<sub>2</sub> dehydration and interim CO<sub>2</sub> holding facilities.

GHG Emissions associated with capture and compression processes are accounted for either at the regulated or opt-in facility or in the project condition as part of the CO<sub>2</sub> capture and/or compression system, as applicable.

Carbon dioxide captured by Direct Air Capture facilities may be eligible capture sources through flexibility mechanisms outlined in section 1.4 Flexibility Mechanisms.

### Transport

The transportation system may be a pipeline including booster compression and/or pumps to transport CO<sub>2</sub> from the capture facility to the injection well(s). Alternatively, transportation could be CO<sub>2</sub> moved by vehicle from the capture facility to the injection wells or to a transload receiving facility on a CO<sub>2</sub> pipeline.

Pipeline transportation system infrastructure may include equipment such as electrical or mechanical compressors or pumps, and a pipeline network connecting the capture site to the injection site with line block valves and metering equipment. Supervisory Control And Data Acquisition (SCADA) systems or other systems may be used to collect and transmit data from the pipeline to a control centre and to monitor line block valves. CO<sub>2</sub> is typically transferred in a dense phase. Emissions arising from the inline compression and pumping of CO<sub>2</sub> are accounted for as part of the transport system.

### Geologic Sequestration Target Storage Zone(s)

The CO<sub>2</sub> storage infrastructure may include injection wells, measurement and gas analysis equipment, pumping equipment and flow lines from the main transportation system to the individual injection wells.

Metering of injected fluid quantities and CO<sub>2</sub> concentration to calculate injected CO<sub>2</sub> quantity takes place as close as reasonably practicable to the injection point and must be described by project schematics. A mass balance approach may be appropriate if measured parameters are provided for all inputs except for the one variable being solved for.

### Quantification Protocol for Carbon Dioxide Capture and Permanent Geologic Sequestration v2.1

Once injected into the targeted sequestration scheme geologic storage zone(s) as defined by the D065 CO<sub>2</sub> sequestration scheme approval, CO<sub>2</sub> is contained within the pore spaces of the reservoir. A targeted geologic storage zone(s) may include depleted reservoirs. Geologic storage, with the exception of adsorption, is most efficient at depths where the formation pressure and temperature are sufficient to cause CO<sub>2</sub> to remain in a dense state.

CO<sub>2</sub> is stored by one or more of the following trapping mechanisms:

- Structural trapping below an impermeable, confining layer (cap rock);
- Residual trapping (retention as an immobile phase trapped in the pore spaces of the project reservoir);
- Solubility trapping (CO<sub>2</sub> dissolved into the fluids that saturate the pore space within a project reservoir);
- Mineralization trapping (precipitation as a carbonate material); and
- Adsorption onto organic matter in coal and shale (i.e., CO<sub>2</sub> bonds with geologic formation).

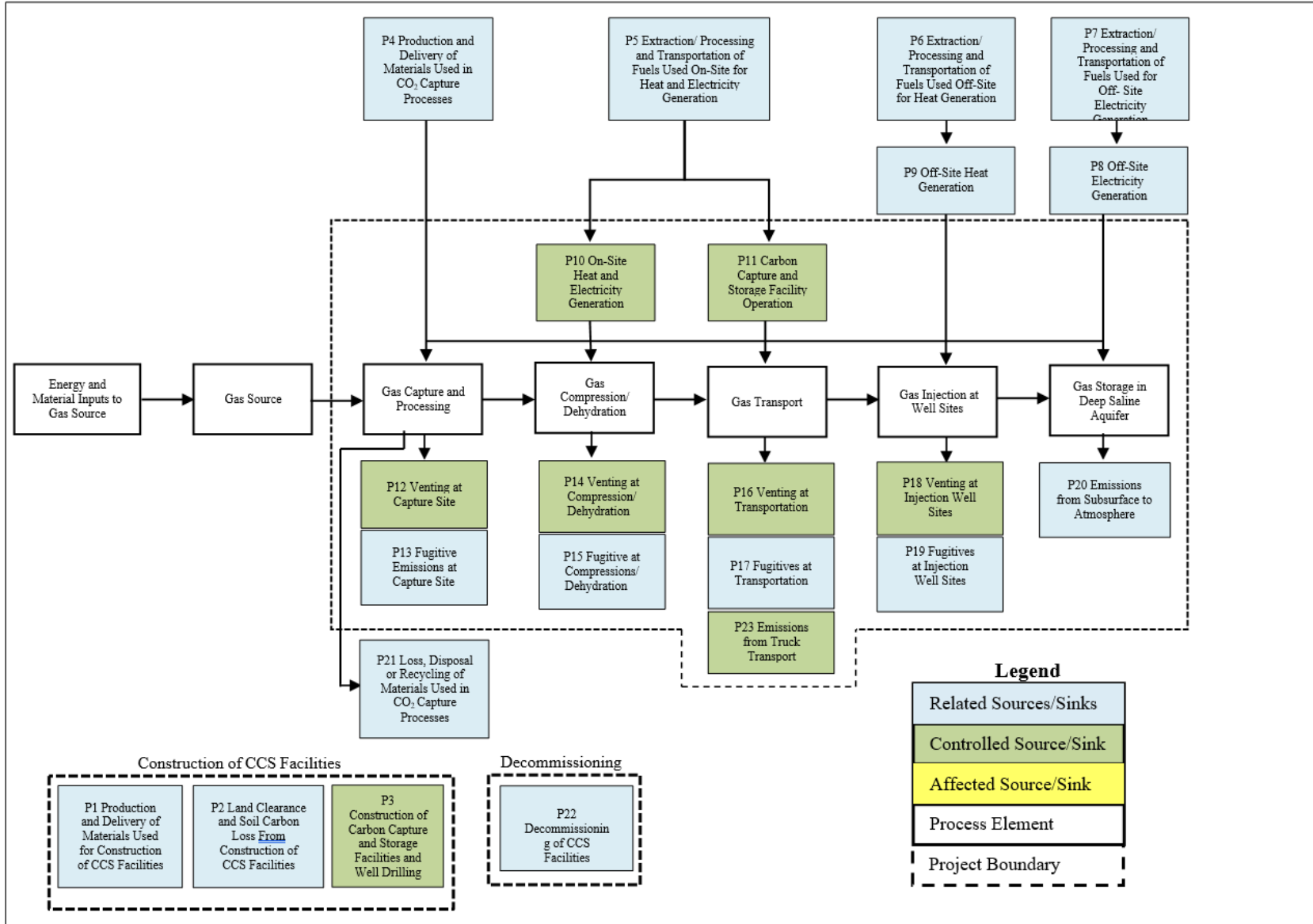
All emissions associated with storage operations, including vented and fugitive emissions at the injection site (after the injection meter) and from the subsurface, are accounted for in the project condition and are subject to the terms of the Directive 065 approval for compliance.

### **3.1 Identification of Project Sources and Sinks**

Sources and/or sinks for the project condition are based on existing best practice guidance contained in other similar and relevant greenhouse gas quantification protocols, ISO 14064-2 (2019), and carbon capture and storage project configurations. This process confirmed that sources and/or sinks in the process flow diagram covered the full scope of eligible project activities under this protocol. Process elements are described in Table 3.

These sources and/or sinks are further refined according to the lifecycle categories identified in Figure 3. These sources and/or sinks are further classified as controlled, related or affected as described in Figure 4.

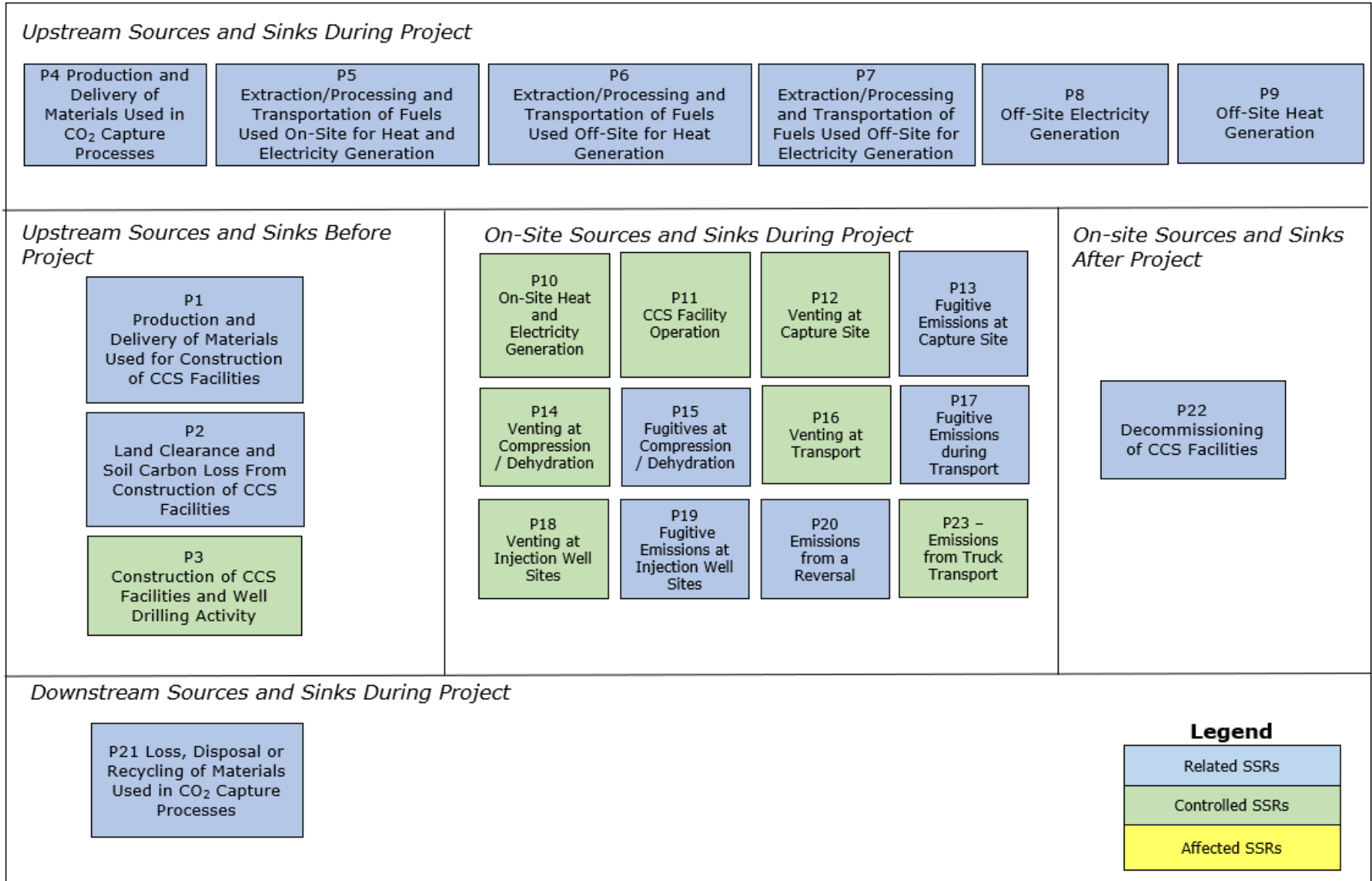
Figure 3: Process Flow Diagram for the Project Condition



**Table 3: Project Process Elements**

<b>Process Element</b>	<b>Description</b>
Energy and Material Inputs to Gas Source	Energy and material inputs to the gas source require inputs such as electricity, heat and fuel, which may be supplied from on-site or off-site sources. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Source	The gas source includes any type of process that generates CO <sub>2</sub> -rich gas. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Capture and Processing	The CO <sub>2</sub> -rich gas stream coming from the gas source may need further purifying and processing before it can be injected. The capture technology applied at the capture facility may use chemical solvent such as amine regeneration. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Compression and Dehydration	The CO <sub>2</sub> -rich gas stream must be compressed before it can be transported to the disposal site. Dehydration may also be required to prevent hydrate formation. This may be achieved through heating or other processes. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Transport	The CO <sub>2</sub> -rich gas stream will be transported via pipeline to the injection site. Depending on the length of the pipeline, additional compression may be needed. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Injection at Wells	The CO <sub>2</sub> -rich gas stream will be injected into the underground formation. In certain cases, additional energy inputs may be required at the injection wells for the injection operation or to operate monitoring equipment. Process elements are included for illustrative purposes only, and they do not affect the quantification.
CO <sub>2</sub> Storage in Targeted Geologic Zone(s)	The CO <sub>2</sub> -rich gas stream will be disposed in a geologic zone(s) suitable for permanent storage of injected CO <sub>2</sub> . Process elements are included for illustrative purposes only, and they do not affect the quantification.

Figure 4: Project Condition Sources and Sinks



**Table 4: Project Condition Sources and Sinks**

Source/Sink	Description	Type
<i>Upstream Sources and Sinks Before Project</i>		
P1 - Production and Delivery of Materials Used for Construction of Carbon Capture and Storage Facilities	Materials used in the construction of carbon capture and storage facilities such as steel and concrete will need to be manufactured and delivered to the site. Emissions are attributed to fossil fuel and electricity consumption for material manufacture and fossil fuel consumption for material delivery.	Related
<i>On-site Sources and Sinks Before Project</i>		
P2 - Land Clearing and Soil Carbon Loss from Construction of Carbon Capture and Storage Facilities	The clearing of vegetative or forest land for site preparation may cause soil to release carbon dioxide into the atmosphere that was previously stored in soil.	Related
P3 - Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	Site construction will require a variety of heavy equipment, smaller power tools, cranes, generators and well drilling operations. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity and from the potential kick or blowout event that could release hydrocarbons during the drilling of injection and monitoring wells.	Controlled
<i>Upstream Sources and Sinks During Project</i>		
P4 - Production and Delivery of Material	Material inputs for CO <sub>2</sub> capture and processing are required. These inputs may be specialized chemicals or additives such as amines. Greenhouse gas emissions are attributed to the fossil fuel consumption for	Related

Inputs used in CO <sub>2</sub> Capture Process	transport of these materials, and the electricity and fossil fuel inputs for their production. The total aggregate quantity of each chemical delivered to the site must be tracked.	
P5 - Extraction/Processing and Transportation of Fuels Used On-Site for Heat and Electricity Generation	The fuels used for heat and electricity generation will need to be extracted, processed, and delivered to the site. Delivery may include shipments by truck, rail or pipeline. CO <sub>2</sub> , CH <sub>4</sub> and N <sub>2</sub> O emissions are associated with these activities. Volumes and types of fuels used must be tracked.	Related
P6 - Extraction/Processing and Transportation of Fuels Used Off Site for Heat Generation	The fuels used for heat generation will need to be extracted, processed, and delivered to the off-site facility. Delivery may include shipments by truck, rail or pipeline. CO <sub>2</sub> , CH <sub>4</sub> and N <sub>2</sub> O emissions are associated with these activities. Volumes and types of fuels used must be tracked.	Related
P7 - Extraction/Processing and Transportation of Fuels Used Off Site for Electricity Generation	The fuels used for the generation of off-site electricity must be extracted, processed, and delivered to the generating stations. Delivery may include shipments by truck, rail or pipeline. CO <sub>2</sub> , CH <sub>4</sub> and N <sub>2</sub> O emissions are associated with these activities. The quantity of off-site electricity used to operate the carbon capture and storage facilities must be tracked.	Related
P8 – Off-Site Electricity Generation	The total quantities of electricity used and electricity imported by the capture facilities, the transport facility and injection facilities must be tracked to estimate related greenhouse gas emissions.	Related
P9 - Off-Site Heat Generation	Emissions associated with generation of thermal energy off site. Off-site heat delivered to the emission offset project may have been generated independently.	Related
<i>On-Site Sources and Sinks During Project</i>		

P10 - On-Site Heat and Electricity Generation	Heat, steam and electricity inputs may be required for CO <sub>2</sub> capture, processing, compression, dehydration, transportation and injection. Heat and electricity may be generated independently or from cogeneration within the project boundary. The quantity and type of fuels consumed to generate electricity and heat, and the quantity of heat and electricity consumed by the project from each generating source must be tracked.	Controlled
P11 - Carbon Capture and Storage Facility Operation	The CO <sub>2</sub> pipeline and injection well must undergo regular inspection and monitored for leaks. The geological formation must also be monitored and tested regularly for signs of CO <sub>2</sub> leakage and/or migration consistent with the approved Monitoring, Measurement, and Verification Plan requirements associated with the D065 CO <sub>2</sub> sequestration scheme approval. Greenhouse gas emissions are released from fossil fuels consumed for maintenance activities for leak prevention and repair. There may also be fuel use related to the project that doesn't result in the generation of heat or electricity that must be quantified. These stationary and mobile sources may have natural gas, propane, and diesel energy inputs. Quantities and types for each of the energy inputs must be tracked.	Controlled
P12 - Venting of CO <sub>2</sub> at Capture Site	Some CO <sub>2</sub> is vented during the project condition. This may occur for a number of operational reasons and may be necessary for equipment maintenance or emergency shutdowns.	Controlled
P13 - Fugitive Emissions at Capture Site	Unintended leaks of gas from the CO <sub>2</sub> capture and processing unit may occur through faulty seals, loose fittings, or equipment. These gases will be primarily composed of H <sub>2</sub> and CO <sub>2</sub> .	Related
P14 – Venting of CO <sub>2</sub> during Compression / Dehydration	Planned and emergency CO <sub>2</sub> venting may be necessary for compressor and dehydrator maintenance and/or emergency shutdowns.	Controlled
P15 – Fugitive Emissions During Compression / Dehydration	Unintended leaks of gas from the compressor and/or dehydrator may occur through seals, loose fittings, equipment, or compressor packing. These gases will be composed primarily of CO <sub>2</sub> with trace amounts of other gases.	Related

P16 - Venting of CO <sub>2</sub> During Transportation	Planned and emergency CO <sub>2</sub> venting may be necessary for pipeline maintenance and/or shutdowns.	Controlled
P17 - Fugitive Emissions During Transportation	Unintended leaks of gas from the CO <sub>2</sub> pipeline, transportation equipment, and additional compressors may occur through seals, loose fittings, equipment, or compressor packing. These gases will be composed primarily of CO <sub>2</sub> with trace amounts of other gases.	Related
P18 - Venting of CO <sub>2</sub> at Injection Well Sites	Planned and emergency CO <sub>2</sub> venting may be necessary for injection well work overs, mechanical integrity checks, and maintenance. Instances of venting must be logged, including the duration of the venting event and the estimated volume of CO <sub>2</sub> vented.	Controlled
P19 - Fugitive Emissions at Injection Well Sites	Unintended leaks of gas at the CO <sub>2</sub> injection well sites may occur through valves, flanges, pipe connections, mechanical seals, or related equipment. These gases will be composed primarily of CO <sub>2</sub> with trace amounts of other gases. These emissions must be quantified.	Related
P20 - Emissions from a Reversal	Accidental emissions to the atmosphere may occur from gas migration through undetected faults, fractures and/or subsurface equipment resulting from compromised casing/cement/wellhead or packer/tubing. These emissions must be quantified.	Related
P23 – Emissions from Truck Transport	Vehicles may be used to transport CO <sub>2</sub> to the injection site for the purpose of sequestration. Greenhouse gas emission result from the fossil fuels combusted.	Related
<i>Downstream Sources and Sinks During Project</i>		
P21 - Loss, Disposal, or Recycling of Materials Used in CO <sub>2</sub> Capture Processes	Material inputs are either disposed or recycled at the end of their useful life. Greenhouse gas emissions result from the transportation of materials to industrial landfill and/or material recycling processes. Emissions are also associated with the loss of material during project operation. These emissions must be quantified.	Related
<i>Downstream Sources and Sinks After Project</i>		

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P22 - Decommissioning  
Carbon Capture and  
Storage of Facilities

Infrastructure is decommissioned at the end of project operations. This involves the disassembly of the equipment, demolition of on-site structures, landfill disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions result from fossil fuels combustion and electricity use.

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Related

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## 4.0 Quantification

Baseline and project conditions were assessed against each other to determine the scope of emissions for geological sequestration quantified under this protocol. The sources, sinks and reservoirs (SSRs) are either included or excluded depending on how they are impacted by the project activity. SSRs that are not expected to change between baseline and project condition are excluded from quantification. It is assessed that excluded SSRs will either occur at the same magnitude and emission rate during the baseline and project or are functionally equivalent or are not impacted by the activity.

Emissions that increase or decrease as a result of the project may be included and associated greenhouse gas emissions are therefore quantified as part of this protocol.

SSRs are identified in Table 5 as included or excluded and the justification for each.

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**Table 5: Comparison of Sources and Sinks**

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
<i>Upstream Sources and Sinks Before Project</i>				
P1 - Production and Delivery of Materials Used for Construction of Carbon Capture and Storage Facilities	N/A	Related	Exclude	This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project. Its exclusion is consistent with other approved protocols in the Alberta emission offset system.
<i>Upstream Sources and Sinks Before Project</i>				
P2 - Land Clearance and Soil Carbon Loss from Construction of Carbon Capture and Storage Facilities	N/A	Related	Exclude	This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project. Its exclusion is consistent with other approved protocols in the Alberta emission offset system.
P3 - Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	N/A	Controlled	Exclude	This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project. Its exclusion may be consistent with other approved protocols in the Alberta emission offset system.
			<b>Include</b> - reportable drilling releases	Any drilling releases that trigger the Alberta Energy Regulator's Directive 059 reporting threshold for kicks or blowouts must be included in the project emissions.
<i>Upstream Sources and Sinks During Project</i>				
P4 - Production and Delivery of Material Inputs used in CO <sub>2</sub> Capture Process	N/A	Related	<b>Include</b>	This source/sink may have a material impact on project emissions resulting from increased upstream chemical production associated with project period chemical usage.

P5 - Extraction/Processing and Transportation of Fuels Used On Site for Heat and Electricity Generation	N/A	Related	<b>Include</b>	This source/sink is likely to have a material impact on projects.
P6 - Extraction/Processing and Transportation of Fuels Used Off Site for Heat Generation	N/A	Related	Exclude	Emissions associated with this source are not known and out of scope due to the use of the emission factor.
P7 - Extraction/Processing and Transportation of Fuels Used for Generation of Off-Site Electricity	N/A	Related	Exclude	Emissions associated with the production of fuel used for grid electricity has been excluded to maintain consistency with other government-approved protocols in the Alberta emission offset system.
P8 - Off-Site Electricity Generation	N/A	Related	<b>Include</b>	This source/sink is likely to have a material impact on projects.
P9 - Off-Site Heat Generation	N/A	Related	<b>Include</b>	This source/sink is likely to have a material impact on projects.
<i>On-Site Source and Sinks During Project</i>				
B1 - Injected CO <sub>2</sub>	Controlled	N/A	<b>Include</b>	This source/sink is the data point against which all project emissions are subtracted. It is used to establish the baseline emissions for the project.
B2 - Injected CH <sub>4</sub>	Controlled	N/A	Exclude	It is conservative to exclude CH <sub>4</sub> from the injected quantity as this would be an impurity in the process stream. Exclusion of this source also avoids a perverse incentive for the inefficient separation of the CO <sub>2</sub> stream.
B3 - Injected N <sub>2</sub> O	Controlled	N/A	Exclude	It is conservative to exclude N <sub>2</sub> O from the injected quantity as this would be an impurity in the process stream. Exclusion of this source also avoids a perverse incentive for the inefficient separation of the CO <sub>2</sub> stream.
P10 - On-Site Heat and Electricity Generation	N/A	Controlled	<b>Include</b>	This source/sink is likely to have a material impact on projects.

P11 - Carbon Capture and Storage Facility Operation	N/A	Controlled	<b>Include</b>	This source/sink is likely to have a material impact on projects.
P12 - Venting of CO <sub>2</sub> at Capture Site	N/A	Controlled	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P13 - Fugitive Emissions at Capture Site	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P14 - Venting of CO <sub>2</sub> During Compression/Dehydration	N/A	Related	Exclude	The vented and fugitive emissions at occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P15 - Fugitive Emissions During Compression/ Dehydration	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P16 - Venting of CO <sub>2</sub> During Transportation	N/A	Controlled	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P17 - Fugitive Emissions During Transportation	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.

P18 - Venting of CO <sub>2</sub> at Injection Well Sites	N/A	Controlled	<b>Include</b>	This source/sink must be included because it occurs downstream of the injection meter. Resulting emissions may have material impact on the project.
P19 - Fugitive Emissions at Injection Well Sites	N/A	Related	<b>Include</b>	This source/sink only includes fugitive emissions emitted at the injection site from surface facilities. These emissions may occur downstream of metering equipment. Fugitive emissions upstream of metering would also have been emissions in the baseline condition and are excluded from project emissions quantification. Fugitive emissions downstream of the metering equipment and upstream of the subsurface must be included. Fugitive emissions downstream of the metering equipment and down hole are quantified in P20 Emissions from a Reversal.
P20 - Emissions from a Reversal	N/A	Related	<b>Include</b>	Under normal operation, this source/sink is negligible and is excluded from quantification. However, emissions from reversal must be quantified and included consistent with the approved measurement, monitoring and verification plan under the D065 CO <sub>2</sub> sequestration scheme approval
P23 – Emissions from Truck Transport	N/A	Related	<b>Include</b>	Emission from fuel used for CO <sub>2</sub> transport by truck to the injection site for the purposes of sequestration must be quantified and included.
<i>Downstream Sources and Sinks During Project</i>				
P21 - Loss, Disposal, or Recycling of Materials Used in CO <sub>2</sub> Capture Processes	N/A	Related	<b>Include</b>	This source/sink is likely to have a material impact on projects resulting from increased greenhouse gas emissions associated with downstream chemical loss, disposal or recycling of project period chemical usage.
<i>Downstream Sources and Sink After Project</i>				
P22 - Decommissioning of Carbon Capture and Storage Facilities	N/A	Related	Exclude	This source/sink results in negligible greenhouse gas emissions compared to the expected size and long lifetime of the project. These emissions are excluded consistent with other approved protocols in the Alberta emission offset system.

## 4.1 Project Quantification Methodology

The quantification methodology includes net emission reductions, offset-eligible emission reductions and priced emission reductions. In some projects, some SSRs may be subject to a carbon price, whereas in others they may not be subject to a carbon price. The project developer will need to determine if the SSRs are subject to a carbon price and whether or not they are included in the offset-eligible or priced emission reduction, depending on the project and the regulatory status of the site at which the project is implemented. Regardless, the net geological sequestration as a result of this emission offset project is quantified by calculating associated emissions and CO<sub>2</sub> geological sequestration from included SSRs in both the baseline and project conditions and calculating the difference Table 6 outlines the required quantification methodology in application of this protocol.

Quantification of the emissions, reductions, and reversals of relevant SSRs for each of the greenhouse gases must be completed using the quantification procedures outlined below. These quantification procedures serve to complete the following equations for calculating the emission reductions from the comparison of the baseline and project conditions emissions.

Essential to the quantification is an understanding and appropriate treatment of carbon pricing, either federal and/or provincial, on the calculation of the offset eligible emission reductions. Emissions and reductions that are not subject to a carbon price or surcharge (or exempt from a carbon price) are eligible for emission offsets. Facilities regulated under TIER are exempt from the federal fuel charge and CO<sub>2</sub> exported from the regulated facilities is eligible to be sequestered and generate emission offsets. Emissions and reductions that are subject to a carbon price or surcharge are not eligible for emission offsets. The equations for priced emissions are primarily applicable to sources that combust fossil fuels. Projects that quantify emission offsets must also quantify and report priced (non-offset eligible) emissions and reductions.

Projects must identify and categorize all baseline and project emission SSRs included in the quantification as either “priced” or “non-priced” sources of emissions based on applicable federal and/or provincial legislation that is in place during the reporting period covered by the offset project report. Priced emission sources are to be reported but are not included in the calculation of emission offsets. Net geological sequestrations are calculated based on the difference between eligible Baseline and Project quantification.

## 4.2 Net Geological Sequestration

Outlined below is the general approach to quantifying the net geological sequestration.

<b>Project GHG Statement (the following items must be listed separately in the offset project report and be itemized by reporting period and by vintage year)</b>
$\text{Discounted Emission Reductions (year)} = \text{Injected CO}_2 * \text{Df}$
$\text{Net Geological Sequestration (year)} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}} - \text{Discounted Emission Reductions}$
Df = Discount factor applied to injected CO <sub>2</sub> for unintentional reversals. Set equal to 0.005.

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

**Emissions<sub>Baseline</sub>** =

$$\text{Emissions}_{\text{Injected CO}_2} - \text{CO}_2 \text{ injected originating within project boundary}$$

**Emissions<sub>Project</sub>** =

$$\text{Emissions}_{\text{Production and Delivery of Material Inputs}} +$$

$$\text{Emissions}_{\text{Construction and Well Drilling}} +$$

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Emissions Fuel Extraction and Processing +

Emissions Off-Site Electricity Generation +

Emissions Off-Site Heat Generation +

Emissions On-Site Heat and Electricity Generation +

Emissions Carbon Capture, Transport and Storage Facility Operation +

Emissions Venting of CO<sub>2</sub> at Injection Well Sites +

Emissions Fugitives from Injection Well Sites +

Emissions Subsurface to Atmosphere +

Emissions Loss, Disposal or Recycling of Material Inputs +

Emissions Truck Transport –

CO<sub>2</sub> injected originating within project boundary

Where:

Emissions<sub>Baseline</sub> = emissions projected from the measured quantity of CO<sub>2</sub> injected in the project condition, (but does not include CH<sub>4</sub> and N<sub>2</sub>O) less CO<sub>2</sub> injected originating within the project boundary.

Emissions<sub>Injected CO<sub>2</sub></sub> = emissions under B1 Injected CO<sub>2</sub>

Emissions<sub>Project</sub> = sum of the emissions under the project condition

Emissions<sub>Construction and Well Drilling</sub> = emissions under P3 Construction of CCS Facility and Well Drilling Activity

Emissions<sub>Production and Delivery of Material Inputs</sub> = emissions under P4 Production and Delivery of Materials Used in the CO<sub>2</sub> Capture Process

Emissions<sub>Fuel Extraction and Processing</sub> = emissions under P5 Extraction/ Processing and Transportation of Fuels Used On-Site for Heat and Electricity Generation

Emissions<sub>Off-Site Electricity Generation</sub> = emissions under P8 Off-Site Electricity Generation

Emissions<sub>Off-Site Heat Generation</sub> = emissions under P9 Off-Site Heat Generation

Emissions<sub>On-Site Heat and Electricity Generation</sub> = emissions under P10 On-Site Heat and Electricity Generation - CO<sub>2</sub> injected originating within project boundary

Emissions<sub>Carbon Capture Transport and Storage Facility Operation</sub> = emissions under P11 Carbon Capture and Storage Facility Operation

Emissions<sub>Venting CO<sub>2</sub> at Injection Well Sites</sub> = emissions under P18 Venting at Injection Well Sites

Emissions<sub>Fugitives from Injection Well Sites</sub> = emissions under P19 Fugitives at Injection Well Sites

Emissions<sub>Subsurface to Atmosphere</sub> = emissions under P20 Emissions from a Reversal

Emissions<sub>Truck Transport</sub> = emissions under P23 Emissions from Truck Transport

Emissions<sub>Loss, Disposal or Recycling of Material Inputs</sub> = emissions under P21 Emissions from Loss, Disposal or Recycling of Materials Used in CO<sub>2</sub> Capture Process

CO<sub>2</sub> injected originating within project boundary is included in project emissions through quantification of fuel use within the project and in baseline emissions through metering of injected volumes. These cancel and no explicit quantification is required for this term.

GWP<sub>CO2</sub>, GWP<sub>CH4</sub>, GWP<sub>N2O</sub> = Global warming potential of applicable GHG

#### 4.2.1 Flexibility Mechanism 1.4.3 – Limiting Liability to Three Years of Annual Average Injection

Outlined below is the approach for quantifying the net geological sequestration for Projects who elect to limit reversal liability to three years of average annual injection (calculated as an annual average over the life of the crediting period, multiplied by three years) through 1.4.3 Flexibility Mechanism 3: Limiting Impact of Reversals to TIER Credits Through Increased Discount Factor.

**Project GHG Statement (the following items must be listed separately in Project Report and be itemized by reporting period and by vintage year)**

$$\text{Discounted Emission Reductions (year)} = \text{Injected CO}_2 * Df$$

$$\text{Net Geological Sequestration (year)} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}} - \text{Discounted Emission Reductions}$$

Df = Discount factor applied to injected CO<sub>2</sub> for unintentional reversals. Set equal to 0.005 for emission offset project reporting period year 1, 2, 3 inclusive then 0.01 for year 4 onward for each reporting period, including any extensions.

For this purpose, years are defined as the 12-month periods after a project commences, and the year start date for the determination of the Df rate should align with the first day of the initial project reporting period. Note that Df may change during a reporting period as the reporting period spans the transition from year 3 to 4.

Emissions<sub>baseline</sub> and Emissions<sub>project</sub> quantification remain the same as shown in section 4.2 **Net Geological Sequestration**.

#### 4.3 Offset Eligible Emission Reductions (non-priced emissions)

Reductions or sequestration of emissions that are not subject to a carbon price are eligible to be quantified for emission offsets; reductions of emissions that are subject to a carbon price are not eligible to be quantified for emission offsets. Projects that quantify offset eligible emission reductions must also quantify and report on priced emission reductions as per section 4.3.1.

$$\text{Offset Eligible Emission Reductions} = \text{Emissions}_{\text{Non-priced Baseline}} - \text{Emissions}_{\text{Non-priced Project}}$$

##### 4.3.1 Priced Emission Reductions

Emission reductions that are subject to a carbon price are not eligible for emission offsets. Projects must quantify and report on reductions of emissions that are subject to a carbon price in their offset project report.

Priced emission reductions are calculated from a comparison of project and baseline emissions for all SSRs that are subject to a carbon price. Some emissions may be subject to a carbon price in some scenarios and not in others. It is the responsibility of the emission offset project developer to ensure that SSRs that are subject to a carbon price are included in the quantification of priced emission reductions. The third-party assurance provider will need to confirm via project schematics, operational records, and data, that the quantification methodology applied to the project's GHG Statement is consistent with this protocol.

### 4.3.2 Negligible Emissions

Emission offset project developers can apply via a deviation request to the Director for alternative measurement and quantification requirements associated with emissions that fall under the negligibility threshold defined as “negligible emission sources” under the Alberta Greenhouse Gas Quantification Methodologies.

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Table 6: Quantification Methodology

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
<i>Baseline Sources and Sinks</i>						
B1 – Injected CO <sub>2</sub>	<p>Where: Volumetric flow measurement is used:</p> $\text{Emissions}_{\text{Injected CO}_2} = \sum (\text{Vol.}_{\text{Injected Gas}} * \% \text{CO}_2 * \rho_{\text{CO}_2})$ <p>Where: Mass flow measurement is used:</p> $\text{Emissions}_{\text{Injected CO}_2} = \sum (\text{Mass Fraction}_{\text{CO}_2, \text{normalized}} * \text{Mass}_{\text{Gas}})$					
	Emissions <sub>Injected CO<sub>2</sub></sub>	t of CO <sub>2</sub> e	N/A	This value refers to the injected quantity of New CO <sub>2</sub> measured at the metering point in the project condition. The measured volume, composition, temperature and pressure are used to calculate the mass of CO <sub>2</sub> (excludes CH <sub>4</sub> and N <sub>2</sub> O).	N/A	Mass of CO <sub>2</sub> to be calculated from direct measurement and corrected for temperature and pressure, using the standard temperature and pressure as defined in the Alberta Quantification Methodologies. Frequency of metering is highest level possible.
	Volume of injected gas / Vol. <sub>Injected Gas</sub>	m <sup>3</sup>	Measured	Direct metering of volume of gas measured at the metering point in the project condition over the reporting period, measured directly at each injection well.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	Density of injected CO <sub>2</sub> / ρ <sub>Injected CO<sub>2</sub></sub>	Tonne / m <sup>3</sup>	Estimated	Must use a reference density, corrected to the conditions at which the volumes of gas are reported.  Data conversions from all pressure and temperature compensated	Daily	Densities must be used consistently throughout project.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Concentration of injected CO <sub>2</sub> / % CO <sub>2</sub>	%Volume	Measured	<p>instruments must be sure to use the same pressure or temperature used for the specific meter calibration.</p> <p>The CO<sub>2</sub> concentration must be directly measured downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point. When additional CO<sub>2</sub> streams comeingle with a capture stream of known concentration, the concentration of comingled stream must be confirmed either by direct measurement of the comingled stream or by mass balance and a measurement of the additional capture stream. The measurement sample point may occur downstream of the tie in such that the concentration of the comingled stream is taken. Alternatively, the measurement can be taken downstream of the additional capture stream but upstream of comingling. In this case, the concentration of the comingled stream can be calculated by solving a single variable mass balance equation.</p>	Daily	A minimum of daily samples averaged monthly on volumetric basis.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Mass Gas	Tonnes	Measured	Direct metering of mass of gas measured at the metering point in the project condition over the reporting period, measured directly at each injection well.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	Mass Fraction CO <sub>2</sub> , normalized*	%	Measured	The CO <sub>2</sub> mass fraction must be directly measured downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point. When additional CO <sub>2</sub> streams comingled with a capture stream of known concentration, the concentration of comingled stream must be confirmed either by direct measurement of the comingled stream or by mass balance and a measurement of the additional capture stream. The measurement sample point may occur downstream of the tie in such that the concentration of the comingled stream is taken. Alternatively, the measurement can be taken downstream of the additional capture stream but upstream of comingling. In this case, the concentration of the comingled stream can be calculated by solving a single variable mass balance equation. * Note: normalization of the mass fraction of CO <sub>2</sub> requires measurement of other	Daily	The mass fraction of CO <sub>2</sub> is dependent upon the mass fraction of all components in the stream. If components totaling 99.5% of mass fraction are measured, the unmeasured components should have an immaterial effect on injected CO <sub>2</sub> .

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				components that sum to at least 99.5% of the known components in the stream.		
<i>Project Sources and Sinks</i>						
P3 – Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	<i>Emissions Drilling Injection Well Sites = <math>\sum (Vol._{Gas Kick} * \%_{i CO_2, CH_4, N_2O} * \rho_{i CO_2, CH_4, N_2O}) * GWP_{CO_2, CH_4, N_2O}</math></i>					
	Emissions Venting at Injection Well Sites	t of CO <sub>2</sub> e	N/A	N/A	N/A	Quantity being calculated.
	Volume of Vent Gas / Vol. Gas Kick	m <sup>3</sup>	Estimated	If the drilling activity resulted in a kick or a blowout, Directive 059 submission is triggered. The values submitted in the Directive 059 report should be used to estimate the volume of gas released.	Engineering estimate per event	The measurement approach should follow Directive 059 instructions and should be as frequent as the event.
	Concentration in Vent Gas / % CO <sub>2</sub> ,CH <sub>4</sub> ,N <sub>2</sub> O	%	Measured	A measured gas analysis must be obtained.	Per event	Must be as frequent as occurrence of kick or blowout event(s).
			Estimated	Must be determined based on process knowledge and/or engineering estimates.	Per event	
Density of vented gas / $\rho_{i CO_2, CH_4, N_2O}$	Tonne/m <sup>3</sup>	Estimated	Must use a reference density, corrected to the conditions at which the volumes of gas are reported.	N/A	Densities must be used consistently throughout project.	

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				Data conversions from all pressure and temperature compensated instruments must be sure to use the same pressure or temperature used for the specific meter calibration.		
	GWP <sub>CO2,CH4,N2O</sub>	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
P4 -Production and Delivery of Material Inputs used in CO <sub>2</sub> Capture Process	<i>Emissions</i> Production & Delivery of Material Inputs = $\sum (Input_i * EF_{Input_i CO_2, CH_4, N_2O}) * GWP_{CO_2, CH_4, N_2O}$					
	Emissions <sub>Production &amp; Delivery of Material Inputs</sub>	t of CO <sub>2</sub> e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture and storage operations.
	Quantity of material inputs consumed for carbon capture and storage facility operation / Input <sub>i</sub>	t/L/m <sup>3</sup> / Other	Estimated	Estimation of the quantity of material inputs consumed for the carbon capture and storage project.	Annual	Engineering report will specify the quantity of material input required for an appropriately sized carbon capture and storage facility. Represents most reasonable means of estimation.
	Emissions factor for each type of material input / EF Input <sub>i CO2, CH4, N2O</sub>	t CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O per t/L/ m <sup>3</sup> /other	Estimated	Project specific design.	Annual	Production and delivery estimates for the emission factors for the material inputs.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	GWP <sub>CO2,CH4,N2O</sub>	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
P5 Extraction Processing and Transport of Fuels Used On Site for Heat and Electricity Generation	<i>Emissions<sub>Fuel Extraction and Processing</sub> = <math>\sum (Fuel_i * EF_{Fuel_i CO_2, CH_4, N_2O}) * GWP_{CO_2, CH_4, N_2O}</math></i>					
	Emissions <sub>Fuel Extraction and Processing</sub>	t of CO <sub>2</sub> e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of fossil fuels used at each component of the carbon capture and storage operations.
	Total Quantity of fossil fuels consumed to operate carbon capture and storage facilities / Fuel <sub>i</sub>	M <sup>3</sup> /MJ/ Other	Measured	Direct measurement of the quantity of fossil fuels consumed at each component of the carbon capture and storage project.  Where direct measurement is not available proration of fuel to specific equipment based on total fuel metering is acceptable.	Continuous metering	Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture and storage operations.
	Emissions factor for extraction and processing of each type of fuel / EF <sub>Fuel<sub>i</sub> CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O</sub>	t CO <sub>2</sub> , CH <sub>4</sub> or N <sub>2</sub> O per m <sup>3</sup> /MJ/other	Estimated	From CAPP or other reference documents. Refer to Carbon Offset Emission Factors Handbook	Annual	Reference values represent best available emission factors for fuel extraction and processing.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	GWP <sub>CO2,CH4,N2O</sub>	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
P8 - Off-Site Electricity Generation	$\text{Emissions}_{\text{Off-Site Electricity Generation}} = \text{Electricity}_{\text{import}} * EF_{\text{Electricity}}$ $EF_{\text{electricity}} = \text{Carbon Offset Emission Factors Handbook (use increased on-site grid electricity use (includes line loss))}$					
	Emissions <sub>Off-Site Electricity Generation</sub>	t CO <sub>2e</sub>	N/A	N/A	N/A	Total off-site electricity emissions quantity being calculated based on the quantity of electricity sourced from outside the project
	Total quantity of delivered electricity consumed for the emission offset project / Electricity <sub>Grid</sub>	MWh	Measured	Direct measurement of electricity delivered to the emission offset project including as appropriate the capture, compression, transport, injection and storage of CO <sub>2</sub> . The total electricity consumption should be calculated as the sum of individual import meters if there are more than one.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail
	Emission intensity factor for electricity generation / EF <sub>electricity</sub>	t CO <sub>2e</sub> / MWh	Estimated	Grid emission intensity factor for each year obtained from the Carbon Offset Emission Factors Handbook. For the vintage years 2025 through 2029 the TIER high-performance benchmark for electricity for that	Annual	Reference value adjusted periodically

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				year may be used, unless otherwise approved by the Director of Emission Offsets for projects whose credits will be transferred outside of TIER or for DAC projects through 1.4.1 Flexibility Mechanism 1: Direct Air Capture Facility as Emissions Source.		
P9 - Off-Site Heat Generation	$\text{Emissions}_{\text{Off-Site Heat Generation}} = \text{Heat} * EF_H$ <p style="text-align: center;">Where:</p> $EF_H = \text{Industrial Heat Benchmark}$					
	Emissions <sub>Off-Site Heat Generation</sub>	t CO <sub>2e</sub>	N/A	N/A	N/A	Quantity being calculated based on total quantity of heat sourced from off site. Sources from a regulated facility and from an industrial facility not regulated are included
	Quantity of heat imported by the emission offset project / Heat	GJ	Measured	Direct measurement of the quantity of heat used by the CO <sub>2</sub> sequestration emission offset project	Continuous metering	Continuous metering is standard for boundary transfer
	Benchmark for Industrial Heat Generation/ EF <sub>H</sub>	t CO <sub>2e</sub> / GJ	N/A	Regulated facilities that export thermal energy to another regulated facility, a CCS emission offset project or an EOR emission offset	Annual	Established industrial heat high-performance benchmark as listed in TIER must be used in all cases.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				project account for it at the TIER benchmark for industrial heat.		
P10 - On-Site Heat and Electricity Generation	$\text{Emissions}_{\text{On-Site Heat and Electricity Generation}} = \sum (\text{Fuel}_{\text{CCS}} * \text{EF}_{\text{Fuel } i, \text{CO}_2, \text{CH}_4, \text{N}_2\text{O}}) * \text{GWP}_{\text{CO}_2, \text{CH}_4, \text{N}_2\text{O}}$ <p>Where:</p> $\text{Fuel}_{\text{CCS}} = (\text{Heat}_{\text{CCS}} / \text{Heat}_{\tau}) * \text{Fuel}_{\text{H}} + (\text{Elec}_{\text{CCS}} / \text{Elec}_{\tau}) * \text{Fuel}_{\text{E}}$ <p>If direct measurement is not available, an optional calculation is provided: <math>\text{Fuel}_{\text{H}} = \text{Fuel}_{\text{H\&amp;E}} * (\text{Heat}_{\tau} / e_{\text{H}}) / (\text{Heat}_{\tau} / e_{\text{H}} + \text{Elec}_{\tau} / e_{\text{E}})</math></p> <p>Where: <math>e = \text{efficiency}</math></p> $\text{Fuel}_{\text{E}} = \text{Fuel}_{\text{H\&E}} - \text{Fuel}_{\text{H}}$					
	Emissions <sub>On-Site Heat and Electricity Generation</sub>	t of CO <sub>2</sub> e	N/A	N/A	N/A	Quantity being calculated based on quantity of heat and power sourced from on-site cogeneration facilities
	Emissions Factor for Combustion of Each Type of Fuel / EF <sub>Fuel i, CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O</sub>	t CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O per L / e <sup>3</sup> m <sup>3</sup> / other	Estimated	Carbon Offset Emission Factors Handbook	N/A	Must use most current factors
	Proportionate Volume of Fossil Fuels Consumed to Generate Heat and Power at On-Site Generation Facilities for Use by	L/ m <sup>3</sup> /Other	Calculated	Calculated relative to the metered quantities of thermal energy and electricity delivered to the carbon capture and storage project from connected heat and power generation facilities.	Monthly	Allocation of Project Emissions based on proportion of total energy output from the combustion unit that is supplied to the carbon capture and storage project is appropriate given that multiple energy users may source thermal

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	the CCS Project / Fuel CCS					energy or electricity from a single combined heat and power plant. Direct metering of thermal energy and electricity is appropriate.
	Volume of Fossil Fuels Consumed to Generate Heat at On- Site Generation Facilities for Use by the CCS Project / Fuel H	L/ m <sup>3</sup> /Other	Measured	Direct measurement of the volume of fossil fuels consumed at the heat and power generation facility and/or other direct connected facilities that provide heat to the carbon capture and storage project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
			Calculated	Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance.
	Volume of Fossil Fuels Consumed to Generate Electricity at On-Site Generation Facilities for Use by the CCS Project / Fuel E	L/ m <sup>3</sup> /Other	Measured	Direct measurement of the volume of fossil fuels consumed at the heat and power generation facility and/or other direct connected facilities that provide power to the carbon capture and storage project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
			Calculated	Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance.
	Total Volume of Fossil Fuels Consumed to Generate Heat and Power at the Combined Heat	L/ m <sup>3</sup> /Other	Measured	Direct measurement of the volume of fossil fuels consumed at the combined heat and power generation facility and/or other direct connected facilities that provide heat	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	and Power Generation Facilities / Fuel H & E			and/or power to the carbon capture and storage project.		
	Total Quantity of Thermal Energy Supplied to the CCS Project from Generation Facilities / Heat <sub>CCS</sub>	GJ	Measured	Direct metering of quantity of thermal energy received by the carbon capture and storage project from connected heat and power generation facilities (e.g., from dedicated cogeneration facilities, other industrial facilities etc.). Metering of the thermal energy should account for the type of heat transfer medium (steam, hot water, oil, etc.) and the net heat transfer based on mass/volume flow rates of the heat transfer medium to and from the carbon capture and storage equipment (e.g., accounting for the enthalpy of feedwater, boiler blow down and condensate return), temperatures, pressures for superheated steam and other relevant thermodynamic properties as necessary.	Continuous metering	Direct metering of thermal energy is standard practice when thermal energy is provided to a user under a contractual agreement. Frequency of metering is highest level possible. Accounting for the net heat transfer from the heat distribution system based on the specific temperatures and pressures of the heat transfer medium is consistent with best practices.
	Total Quantity of Electricity Supplied to the CCS Project by Generation Facilities / Elec <sub>CCS</sub>	GJ	Measured	Direct metering of the quantity of electricity delivered to the carbon capture and storage from onsite generation. Note that imported electricity usage is accounted for under a separate source/sink and	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
				should not be included in this calculation.		
	Total Quantity of Thermal Energy Supplied to End Users by the Generation Facility in the Project Condition / Heat $\tau$	GJ	Measured	Direct metering of quantity of thermal energy delivered to all end users by the generation plant (including the carbon capture and storage facilities). Metering of the thermal energy should account for the type of heat transfer medium (steam, hot water, oil, etc.) and the net heat transfer based on mass/volume flow rates of the heat transfer medium to and from the capture facility (e.g., accounting for the enthalpy of feedwater, boiler blow down and condensate return), temperatures, pressures for superheated steam and other relevant thermodynamic properties as necessary.	Continuous Metering	Direct metering of thermal energy is standard practice when thermal energy is provided to a user under a contractual agreement. Frequency of metering is highest level possible. Accounting for the net heat transfer from the heat distribution system based on the specific temperatures and pressures of the heat transfer medium is consistent with best practices.
	Total Quantity of Electricity Supplied to End Users by the Generation Facility in the Project Condition / Elec $\tau$	GJ	Measured	Direct metering of quantity of electricity delivered to all direct connected facilities from the generation plant; including the direct metering of the total electricity distributed to the carbon capture and storage facilities, the regional electricity grid and an industrial system designation.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Efficiency of Heat Generation at On-site Generation Unit / e <sub>H</sub>	-	Estimated	Estimated based on total quantity of thermal energy output from generation unit and input energy content of fuels combusted by the generation unit. If a site-specific heat generation efficiency is unavailable, use a default efficiency of 80%.	Annual	Estimation is reasonable given consistency of generation unit operations.
	Efficiency of Electricity Generation at On-site Generation Unit / e <sub>E</sub>	-	Estimated	Estimated based on total quantity of electricity output from generation unit and input energy content of fuels combusted by the generation unit. If a site-specific electric efficiency is unavailable use a default efficiency of 35%.	Annual	Estimation is reasonable given consistency of generation unit operations.
P11 - Carbon Capture and Storage Facility Operation	$Emissions_{Carbon\ capture\ and\ storage\ facility\ operation} = \sum (Fuel_i * EF_{Fuel_i, CO_2, CH_4, N_2O}) * GWP_{CO_2, CH_4, N_2O}$					
	Emissions <sub>Carbon Capture and Storage Facility Operation</sub>	t of CO <sub>2</sub> e	N/A	N/A	N/A	Quantity being calculated based on quantity of fossil fuels used for inspection and maintenance of carbon capture and storage facilities.
	Emissions Factor for Combustion of Each Type of Fuel / EF <sub>Fuel i, CO2, CH4, N2O</sub>	t CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O per L / e <sup>3</sup> m <sup>3</sup> / other	Estimated	Carbon Offset Emission Factors Handbook	N/A	Usage of most current factors per Alberta emission offset system

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Volume of Each Type of Fuel Used CCS Facility Operation/ Fuel <sub>i</sub>	L / m <sup>3</sup> / other	Estimated	Volumes of fuel consumed by each piece of equipment used during the operating activities of the CCS facility may be estimated.	Annual	Quantity being estimated in aggregate form as fuel used at CCS facility is likely aggregated for each source.
	GWP <sub>CO2,CH4,N2O</sub>	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
P18 - Venting at Injection Well Sites	<i>Emissions<sub>Venting at Injection Well Sites</sub> = ∑ (Vol.<sub>Gas Vented</sub> * %<sub>CO2, CH4, N2O</sub> * ρ<sub>CO2, CH4, N2O</sub>) * GWP<sub>CO2, CH4, N2O</sub></i>					
	Emissions <sub>Venting at Injection Well Sites</sub>	t of CO <sub>2</sub> e	N/A	N/A	N/A	Quantity being calculated.
	Volume of Vent Gas / Vol. <sub>Gas Vented</sub>	L / m <sup>3</sup> / other	Estimated	Volume should be estimated based on the pressure, length and diameter of the pipe being serviced.	Per event	This vented gas is downstream of the injection meter during maintenance blowdowns and should be as frequent the maintenance event.
	Composition in Vent Gas / % CO <sub>2</sub> ,CH <sub>4</sub> ,N <sub>2</sub> O	%	Measured	The gas composition shall be directly measured downstream of the capture and processing equipment and as close as possible to the point where CO <sub>2</sub> is injected into the deep saline aquifer.  Mass based composition would also be acceptable.	A minimum of daily samples averaged monthly on volumetric basis	Composition may vary throughout the injection of gas stream. Frequent gas composition measurement is reasonable for operation of an injection facility.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Density of Vent Gas / $\rho_{CO_2,CH_4,N_2O}$	t/m <sup>3</sup>	Estimated	Must use a reference density, corrected to the conditions at which the volumes of gas are reported. Data conversions from all pressure and temperature compensated instruments must be sure to use the same pressure or temperature used for the specific meter calibration.	N/A	Densities must be used consistently throughout project.
	GWP <sub>CO<sub>2</sub>,CH<sub>4</sub>,N<sub>2</sub>O</sub>	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.
P19 - Fugitives at Injection Well Sites	<i>Emissions Fugitives at Injection Well Sites = <math>\sum (Fitting\ i * ER_{Fitting\ i}) + Other\ Fugitive\ Releases</math></i>					
	Emissions Fugitives at Injection Well Sites	t of CO <sub>2</sub> e	N/A	N/A	N/A	Quantity being calculated.
	Other Fugitive Releases	t of CO <sub>2</sub>	Estimated	Engineering estimate.	Per occurrence	This is from unintended/unplanned events, and accounts for CO <sub>2</sub> released after the meter and wellbore but not from the storage container. Estimated based on

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
						the most detailed information available.
	Number of Fittings after Injection Meter / Fitting <sub>i</sub>	N/A	Estimated	Project-specific design.	Once	Estimated based on the number of fittings after the injection meter and above the subsurface.
	Emission Rate for Fitting / ER <sub>Fitting i</sub>	t of CO <sub>2</sub> e /fitting/ year	Estimated	Emission rate based on industry best practices for determining typical fitting emissions based on actual field equipment (fitting sizes, types, operating pressures and gas properties).	Annual	Estimates made for project specifics represent the most accurate means.
P20 -Emissions From a Reversal	<i>Emissions<sub>Subsurface to Atmosphere</sub> = Mass CO<sub>2</sub>e<sub>leaked</sub></i>					
	Mass of CO <sub>2</sub> e leaked from the Subsurface to Atmosphere/ Mass CO <sub>2</sub> e <sub>leaked</sub>	t of CO <sub>2</sub> e	Estimated	If a leak event occurs, the mass of CO <sub>2</sub> e leaked from the subsurface to the atmosphere shall be estimated with a maximum overall uncertainty over the reporting period of ±7.5%. In case overall uncertainty of the applied quantification approach exceeds ±7.5%, an adjustment shall be applied. Refer to Appendix B for further guidance.	N/A	Estimation would be required for reporting to The Alberta Energy Regulatory authority. Direct measurement is likely not possible, but the use of engineering estimates and accounting for the uncertainty would be a reasonable approach in the event leakage occurs.

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P21 - Loss, Disposal or Recycling of Material Used	<i>Emissions</i> Loss, Disposal or Recycling of Material Used = $\sum (\text{Vol. Used}_i * \text{EF Used}_i \text{ CO}_2, \text{CH}_4, \text{N}_2\text{O}) * \text{GWP}_{\text{CO}_2, \text{CH}_4, \text{N}_2\text{O}}$					
	Emissions <sub>Loss, Disposal or Recycling of Material Used</sub>	t of CO <sub>2e</sub>	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity materials used for the carbon capture and storage operations.
	Total Volume of Material Lost, Disposed or Recycled from the Carbon Capture and Storage Facility/Vol. Used <sub>i</sub>	L/ m <sup>3</sup> / Other	Estimated	Estimation of the volume of material inputs lost, disposed or recycled for the carbon capture and storage project.  Must be estimated for material streams of 500 tonnes or greater of CO <sub>2e</sub> annually.	N/A	Engineering report will specify the volume of material input lost, disposed or recycled for an appropriately sized carbon capture and storage facility. Represents most reasonable means of estimation. Loss, disposal or recycling estimates for the emission factors for the materials used.
	Emissions factor for each type of material input / EF Used <sub>i CO2, CH4, N2O</sub>	t CO <sub>2</sub> , CH <sub>4</sub> , N <sub>2</sub> O per L / m <sup>3</sup> / other	Estimated	Project-specific design.	Annual	Production and delivery estimates for the emission factors for the material inputs.
	GWP <sub>CO2,CH4,N2O</sub>	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.
<i>For fuel use tracked by distance:</i>						

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P23 – Emissions from Truck Transport	$Emissions_{Transport} =$ $(\sum [Dist * EF_{i,CO2} * FCR] +$ $\sum [GWP_{CH4} * Dist * EF_{i,CH4} * FCR] +$ $\sum [GWP_{N2O} * Dist * EF_{i,N2O} * FCR]) / 100,000$ <p>For fuel use tracked by fuel receipts:</p> $(\sum [Vol. Fuel_{i,CO2} * EF_{i,CO2}] +$ $\sum [GWP_{CH4} * Vol. Fuel_{i,CH4} * EF_{i,CH4}] +$ $\sum [GWP_{N2O} * Vol. Fuel_{i,N2O} * EF_{i,N2O}]) / 1,000$					
	Emissions <sub>Transport</sub>	t CO <sub>2e</sub> e	N/A	N/A	N/A	Quantity being calculated
	Distance/ <i>Dist</i>	Kilometre (km)	Measured	Truck tickets for round trip based on GPS and/or odometer readings	Per round trip/ delivery	GPS and odometer accurately track distance traveled.
	Fuel economy, <i>FCR</i>	L/100km	Estimated	Government of Canada (2019) <a href="#">Fuel Efficiency Benchmarking in Canada's Trucking Industry study</a>	Per report	As per the Government of Canada (2019) <i>Fuel Efficiency Benchmarking in Canada's Trucking Industry</i> study, the average fuel efficiency of Class 7/8 transport units is 39.5L/100km.
	Fuel combusted, <i>i</i>	Type (Gasoline/ Diesel)	Measured	Manufacturer specifications	Per trip/ delivery	Vehicles are identified as using either gasoline or diesel.
Emission factor for fuel combusted, $EF_{i,CO2}, EF_{i,CH4}, EF_{i,N2O}$	kg/L	Estimated	National Inventory Report 1990-2019: Greenhouse Gas Sources and Sinks in Canada (NIR 2021)	Per trip/ delivery	The 2019 National Inventory Report is referenced in the most recent (2019) version of the Carbon Offset Emission Factors Handbook	

Sources and Sinks	Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
						(3.1). The updated version of this report is used, as it provides greater accuracy and specifies emission factors from heavy-duty diesel vehicles, for which the Carbon Offset Emission Factors Handbook does not.
	Volume of fuel used ,Vol Fuel <sub>i</sub>	L	Measured	As an alternative to estimated fuel use by distance, receipts for fuel consumed by truck can be used if tracked for the project.	Per trip	Fuel receipts can be used to quantify type and volume of fuel used.
	GWP <sub>CO<sub>2</sub>, CH<sub>4</sub>, N<sub>2</sub>O</sub> Global Warming Potential	Unitless	Estimated	Provided in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Must use factors published in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

#### 4.3.3 P8 Off-Site Electricity Generation Quantification Methodology for Flexibility Mechanism 1 Projects

Direct air capture projects may be able to claim electricity generated from a low carbon intensity project if all conditions outlined within this section are met.

Electricity generated from a low carbon intensity project must be delivered to consumers via the established electricity grid, unless the low carbon intensity project is within the same boundary (physical location) as the project using the electricity. This methodology applies only for metered power consumption at a DAC facility which is part of the emission offset project.

Flexibility Mechanism 1 is eligible for emission offset projects with and without a PPA with a lower carbon intensity electricity generation project. However, projects with a PPA can source electricity from a number of low carbon intensity electricity generation projects, such as wind, solar, hydro or biomass generation projects under TIER or WREGIS. In the absence of a PPA, the emission offset project must procure TIER emission offsets from wind or solar projects only.

The following conditions must be met for Flexibility Mechanism 1 projects to quantify P8 at the carbon intensity of the low intensity generation project.

- 1.) Low carbon intensity electricity generation must occur in Alberta and must be physically connected to the same grid as the DAC facility.

- 2.) The low carbon intensity generation project must not have been generating low carbon intensity electricity for more than five years prior to the earlier of the start date of the PPA or the inclusion of the DAC source in the offset project.
- 3.) No double counting can occur:
  - a. For projects without a PPA:
    - i. emission offsets (or emission performance credits) must be serialized at the low carbon intensity project under the TIER emission offset system wind or solar protocol (or based on compliance filing for opted in wind and solar projects) and voluntarily retired without the use of the associated compliance benefit for each MWh being included.
  - b. Where a PPA or virtual PPA is in place,
    - i. emission offsets (or emission performance credits) must be serialized at the low carbon intensity project under the applicable TIER emission offset system protocol (or based on compliance filings for opted in electricity facilities) and voluntarily retired without the use of its compliance benefit for each MWh being included, or
    - ii. renewable energy certificates (RECs) generated through the Western Renewable Energy Generation Information System (WREGIS) can be procured and voluntarily retired.
      - a. Where a portion of the power from a TIER facility or renewable power project is being applied, a rate of offset generation or emission performance credit per MWh produced must be determined for the whole facility in order that the correct number of credits, rounded up to the nearest tonne, are retired for the MWhs claimed.
- 4.) The DAC facility load should participate in the applicable Alberta Electric System Operator Emergency Demand Response Program to enhance provincial grid reliability.

Renewable Electricity Program Renewable Energy Credits are not permitted to be used under this flexibility mechanism.

The quantification process for the portion of P8 up to the metered power consumption of the DAC facility for which low carbon power is claimed would be implemented as follows:

- 1.) Under P8, projects directly meter through continuous metering all electricity consumed by the DAC facility.
- 2.) Project procures and provides evidence to EPA via the project report of the voluntary retirement of a TIER emission offset (or emission performance credit) from the appropriate low carbon intensity generation protocol, or a WREGIS REC from an appropriate project. The total MWh represented by the procured and voluntarily retired low carbon intensity generation attribute must be matched and reported annually.
- 3.) The project balances the MWh consumed by the DAC facility and claimed MWh represented by procured and voluntarily retired credit. If more power is consumed than is covered by the low intensity generation obtained, the normal quantification under P8 should be used for the excess.
- 4.) MWh matched to retired offsets (or emission performance credits), or RECs are permitted to quantify P8 emissions at the lower carbon intensity of the generation process. The emission intensity factor for low carbon electricity generation would be determined based on generation type.
  - a. Alternatively, the project developer can voluntarily retire emission offsets or emission performance credits generated under the TIER emission offset system wind or solar protocols at a rate of the applicable Alberta Electricity Grid Displacement Factor per metered MWh consumed by the DAC facility.

Table 7: Common Quantification Variables

Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justification for measurement or estimation and frequency
Total heat produced by the facility / H	GJ	Measured	Total quantity of heat produced by the facility is determined through direct metering.	Annual calculation of continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
Higher heating value / HHV	GJ/L, m <sup>3</sup> or other	Measured	Measured by a third-party gas analysis or calculated based on gas compositions. Units for HHV and Emission Factor for Fuel must align.	Annual	Frequency of metering provides for reasonable diligence.
CO <sub>2</sub> emission factor for each type of fossil fuel combustion/ EF Fuel <sub>i</sub> CO <sub>2</sub>	t CO <sub>2</sub> e per L, m <sup>3</sup> or other	Estimated	See the latest version of Carbon Offset Emission Factor Handbook.	Annual	Reference values are adjusted periodically use the most current version.
CH <sub>4</sub> emission factor for each type of fossil fuel combustion/ EF Fuel <sub>i</sub> CH <sub>4</sub>	t CO <sub>2</sub> e from kg CH <sub>4</sub> per L, m <sup>3</sup> or other	Estimated	See the latest version of Carbon Offset Emission Factor Handbook.	Annual	Reference values adjusted periodically use the most current version.
N <sub>2</sub> O emission factor for each type of fossil fuel combustion / EF Fuel <sub>i</sub> N <sub>2</sub> O	t CO <sub>2</sub> e from kg CH <sub>4</sub> per L, m <sup>3</sup> or other	Estimated	See the latest version of Carbon Offset Emission Factor Handbook.	Annual	Reference values adjusted periodically Use the most current version.
Total quantity of fuel consumed / Fuel <sub>i</sub>	m <sup>3</sup> / MJ/ kg or other	Measured	Direct measurement of the quantity of fossil fuels consumed at each component of the carbon capture and storage project.	Continuous metering	Quantity being calculated in aggregate based on quantity of fossil fuels used.
		Estimated	Calculate the mass/volume of fuel used for heat or electricity	Annual	Annual fuel consumption estimate should be completed in

			production. Conversions from energy to fuel quantities should use the higher heating value of the fuel. Energy use should be either measured or calculated based on conservative estimate for equipment duty and load.		the absence of direct metering for fuel consumption. Maximum power consumption rates should be used to estimate fuel consumption with higher heating values.
GWP <sub>CO2,CH4,N2O</sub>	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

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## 5.0 Data Management

All emission offset projects must be supported with high-quality data, and methods to fulfill the eligibility and quantification requirements listed in this protocol and be substantiated by records for the purpose of verification to a reasonable level of assurance. TIER requires that data must be quantifiable, measurable directly or by accurate estimation using replicable techniques. A third-party assurance provider is responsible for evaluating the project and any GHG Statements and must reach the same conclusions using evidence-supported data. The Alberta Emission Offset System does not accept data that is based on attestation and only accepts data that is verifiable.

In support of meeting project data requirements, data must be managed in a manner that substantiates:

- Emissions and reductions and sequestration that have been recorded pertain to the offset project activity;
- All emissions sources that should have been recorded were recorded accurately and appropriately;
- Emissions and reductions quantification has been recorded transparently and appropriately;
- Emissions and reductions have been recorded in the correct reporting period;
- Emissions and reductions have been recorded in the appropriate category; and
- Must have an auditable data management system.

The emission offset project developer must establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and location requirements. Verification requirements are outlined in the most current version of the Standard for Validation, Verification and Audit.

### 5.1 Project Monitoring

Monitoring requirements for projects are addressed in two distinct categories: measurement for emission offset quantification purposes; and the monitoring activities that provide operational containment assurance. The first includes measurement activities required to quantify the net geological sequestration of CO<sub>2</sub> from the CO<sub>2</sub> capture, transportation and injection activities that are outlined in this protocol. This first category applies to all projects and the requirements are discussed further below.

The second category pertains to monitoring activities to ensure that the CO<sub>2</sub> injected into sequestration schemes is permanently contained within the targeted geologic storage zone(s). Each project must comply with the relevant Directives and Regulations and any specific monitoring requirements included in the D065 CO<sub>2</sub> sequestration scheme approval.

Approvals to operate a D065 CO<sub>2</sub> sequestration scheme approval are managed by the AER under section 39 of the *Oil and Gas Conservation Act*.

#### 5.1.1 Project Monitoring Requirements for Quantification Purposes

Monitoring requirements include measurement of all relevant parameters to account for all supplemental energy inputs (e.g., fossil fuels, heat and electricity) required for the operations under the D065 CO<sub>2</sub> sequestration scheme approval.

The project measurement devices should be off-the-shelf metering equipment such as gas or fluid flow meters, utility meters (gas and electricity) and gas analyzers. Any assumptions and contingency procedures must be documented. Meters must be maintained to ensure consistent operation with design specifications and must be calibrated according to AER Directive 017 requirements and quantification methodology requirements, otherwise according to manufacturer's specifications. Reference AER Directive 017 Measurement Requirements for Oil and Gas Operations for guidance on calibration frequency for chain of custody meters. Project Developers must require CO<sub>2</sub> chain of custody meters to have the same annual calibration requirements as natural gas chain of custody meters.

Below are additional details for implementing a monitoring plan that accounts for the location, type of equipment, and frequency by which each variable is measured.

### 5.1.2 Project Monitoring Plan for Quantification Purposes

For the purposes of emission reduction quantification under this protocol a monitoring plan must be established for all monitoring and measurement activities associated with the project. This monitoring plan will serve as a basis for third party assurance providers to confirm that the monitoring and measurement requirements have been met, and that consistent, rigorous monitoring and record keeping of measurement is ongoing at the emission offset project site. The monitoring plan must cover all aspects of monitoring and measurement for quantification of emissions contained in this protocol and must specify how data for all relevant parameters listed in Table 6: Quantification Methodology will be measured, collected and recorded. The monitoring plan is designed and developed as part of the offset project plan and must be available during any verification or reverification processes. These monitoring requirements should not be conflated with the monitoring, measurement and verification requirements established under D065.

At a minimum the monitoring plan shall stipulate and include:

- The frequency of data acquisition;
- A record keeping plan;
- Identification of key instrumentation;
- Validation activities to prove the accuracy of gas composition measurements (see section 5 for additional guidance).
- The frequency of instrument calibration activities;
- The QA/QC provisions on data acquisition, management and record keeping that ensure monitoring, and the use and storage of data, is carried out consistently and with precision;
- The role of individuals performing each specific monitoring activity;
- Methods to measure and quantify the following data:
  - Energy inputs required to capture, dehydrate, compress, transport, inject and store CO<sub>2</sub> including:
    - Direct fuel inputs; and
    - Indirect energy inputs or other parasitic loads (e.g., heat or electricity consumption);
- Quantity and concentration of CO<sub>2</sub> sold to third parties including sufficient measurements to support data required;
  - Quantity and concentration of CO<sub>2</sub> injected; and
  - Regular leak detection and repair (LDAR Surveys) to quantify fitting, piping and equipment leaks.

Although some of the above data may not be required for the quantification of emissions, emission reductions, and geological sequestration, they must be tracked and reported for completeness purposes.

Additional measurements may be made to support quantification purposes. At each of the measurement points, the mass of the gas stream must be determined based on the volumetric or mass flow, and composition of the gas stream.

Section 5.1.5 Gas Stream Measurement Requirements and 5.1.6 Measurement and Monitoring Guidance for Energy Inputs provide guidance on the measurement and monitoring requirements. It is also necessary to monitor the incremental energy inputs (fossil fuels and electricity) required to operate the carbon capture and storage project. The general monitoring requirements for fossil fuel and electricity inputs are listed in 5.1.6 Measurement and Monitoring Guidance for Energy Inputs.

### 5.1.3 Physical System Measurement Principles

A single physical system for capturing and/or transporting and sequestering CO<sub>2</sub> may support one or more emission offset project. There may also be cases where project developers are quantifying emissions reductions under different quantification protocols within a common physical system. The following principles must be considered for physical systems when undertaking emissions accounting in hub scenarios:

- At least one capture site or CO<sub>2</sub> intake point and one or more injection well is required for an eligible sequestration project under this protocol.
- The offset plan should include all physically connected elements where CO<sub>2</sub> could be directed for future flexibility within Hub projects.
- Project reporting can cover a single CO<sub>2</sub> route even if many are physically possible as long as annual balancing requirements to physical totals are met.

- All emissions from the physical system must be captured in TIER emission offset projects for conservativeness unless the physical system exclusively serves a single, unshared capture or injection point; or the emissions are from a reversal that is being reported exclusively outside of TIER.

#### 5.1.4 Balancing Confirmation for Physical Systems

Projects (TIER or otherwise) need to total to the physical system (reported on annually) other than emissions which may be double counted. Balancing confirmation must be carried out for the following quantities:

- Total CO<sub>2</sub> entering the system
- Total injected CO<sub>2</sub>
- Total emissions must be greater or equal to total physical system emissions
- Total electricity imported/exported
- Total heat imported/exported

Prorating should be done on CO<sub>2</sub> shares (ratios of CO<sub>2</sub> supplied by each project) unless otherwise mutually agreed upon by all impacted projects (TIER or non-TIER such as voluntary market projects).

Reporting for the physical system, where it is not represented by a single offset project, should be verified annually based on calendar year and will be posted alongside documents for each offset project which it supports in that year. If there are confidentiality concerns associated with physical system reporting documents, please contact the Director, Emission Offsets for alternative handling of physical systems reporting.

Physical system reporting must be done based on calendar year. Projects are permitted to report on a part year for their first year of operations but must align their reporting with the calendar year following the first part year. Projects can report for an entire calendar year, or subdivisions of a calendar year.

Emission offset projects can report on a more frequent basis as long as true-up to annual physical totals occurs. Where a physical system is fully represented by a single offset project no separate reporting for the physical system is required.

#### 5.1.5 Gas Stream Measurement Requirements

##### *Flow Rate of Gas Stream*

Meter readings must be temperature and pressure compensated such that the meter output is converted to standard temperatures and pressures as defined in the Alberta Quantification Methodologies. Estimates of CO<sub>2</sub> concentration and density are not acceptable.

Flow meters must be placed based on manufacturer recommendations.

Flow meters should be located at the input to the transport equipment such that they are downstream of all capture and compression equipment to account for any fugitive losses or venting; and

- Injection flow meters should be as close as possible to the injection wellheads to ensure accurate measurement of the injected volumes.
- Flow meters must be calibrated according to manufacturer specifications and AER requirements. Meters must be checked/calibrated at regular intervals according to these specifications and industry standards.
- When orifice meters are used, since pressure drop is measured and flow rate is calculated within the control logic, the density of the injection gas must be measured as per Table 6: **Quantification Methodology** using a gas analysis. The measured density must be revised and entered into the control logic semi-annually.
- Chain of custody CO<sub>2</sub> flow meters must be calibrated in accordance with AER Directive 17 under the same annual calibration schedule as is advised for natural gas chain of custody meters.
- Ownership transfer must be clearly documented for CO<sub>2</sub> transferred.

It is also necessary to monitor the incremental energy inputs (fossil fuels, heat and electricity) required to operate the carbon capture, transport and injection facilities.

### **Concentration of Gas Stream**

The gas composition shall be metered downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point, while the volume is measured as close as possible to the point where CO<sub>2</sub> is injected into the targeted CO<sub>2</sub> storage zone(s).

The Project must validate the accuracy of selected analyzers. Validation may include a combination of laboratory analysis of samples, performance specification tests from the Alberta Continuous Emission Monitoring System (CEMS) Code, and/or statistical analysis. Validation frequency may be managed adaptively. Frequency should be high to start, may be decreased upon consistent validation and subsequently increased upon inconsistent validation.

### **5.1.6 Measurement and Monitoring Guidance for Energy Inputs**

#### ***Volume of Fossil Fuels Combusted***

Gaseous fossil fuels must use a continuous measurement of the gas flow rate where continuous measurement is defined as one measurement at least every 15 minutes. In the event that gas flow rate is metered by a utility provider and continuous measurement is not accessible, projects may use monthly billing accounting or periodic readings to reconcile gas consumption.

The flow meter readings must be corrected for temperature and pressure using standard temperature and pressure as defined in the Alberta Quantification Methodologies. Density estimates used for emission quantification purposes must be adjusted to corrected standardized temperatures and pressures.

Flow meters shall be placed based on manufacturer recommendations and shall operate within manufacturers specified operating conditions at all times. Flow meters must be calibrated according to manufacturer specifications and shall be checked and calibrated at regular intervals according to these specifications.

Liquid fossil fuels must conduct reconciliation of purchasing records on a quarterly basis and inventory adjustments as needed. Volume or mass measurements are made at purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets is an acceptable means to determine the volumes of fossil fuels consumed to operate the carbon capture and storage project.

#### ***Electricity Consumption***

For electricity consumption continuous measurement of electricity consumption is required, or reconciliation of maximum power rating for each type of equipment and operating hours. In the event that electricity consumption is metered by a utility provider and continuous measurement is not accessible, projects may use monthly billing accounting or periodic readings to reconcile electricity consumption.

Electricity consumption must be from continuously metered data wherever possible; however, in certain cases other loads may be tied into the same electricity meter. Where this occurs, estimates with justification are required. In these cases, the maximum power rating of each piece of equipment is used in conjunction with a conservative estimate of operating hours to estimate the electricity consumption; and electricity meters must be calibrated by an accredited third party in accordance with manufacturer specifications.

### **5.1.7 Monitoring and Reservoir Management Plan for Containment Assurance**

Monitoring, measurement and verification requirements, based on the characteristics of the reservoir and sequestration scheme, are outlined by the AER as part of the D065 CO<sub>2</sub> sequestration scheme approval. It requires each sequestration scheme to undertake specific monitoring and reservoir management activities to ensure the safe and permanent storage of CO<sub>2</sub>. Risk factors for each project may be considered by the AER when determining the conditions of the D065 CO<sub>2</sub> sequestration scheme approval. General risk factors include financial failure, technical failure, management failure, regulatory and social instability, and natural disturbances. The following AER Directives outline specific conditions for measurement and monitoring:

- Directives 007 and 017: requirements for measuring and reporting the amounts of CO<sub>2</sub> injected;

- Directive 020: minimum requirements for well abandonment, testing to detect leakage and mitigation measures in the event of detecting leakage;
- Directive 051: requirements for injection and disposal wells, including the wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements;
- Directive 60: requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities: and
- Directive 065: application requirements for a CO<sub>2</sub> sequestration scheme.

As required in the D065 CO<sub>2</sub> sequestration scheme approval, the annual progress report will provide containment assurance specific to the targeted geologic storage zone(s). The third-party assurance provider must have access to the annual progress report submitted to the AER to ensure no CO<sub>2</sub> has escaped from any wellbores penetrating the project reservoir, and no CO<sub>2</sub> migrated from the subsurface to the atmosphere or out of the targeted geologic storage zone(s), or if it has, that it has been fully accounted for. Hence, the overall objective of the monitoring plan is reservoir management for CO<sub>2</sub> containment assurance.

Where operational containment assurance is required by the AER, the offset project developer shall also provide to the Director, Emission Offsets a subset of the submitted data in the form of a Containment Assurance Report (See Containment Assurance Report Template in Appendix C). It is based on measurement and engineering data that encompasses such items as; the results of reservoir management practices, including quantity and concentration of the injected CO<sub>2</sub>. Additionally, any CO<sub>2</sub> moved outside of the D065 CO<sub>2</sub> sequestration scheme approval area must be reported in the Containment Assurance Report. Operational containment assurance may include results from other monitoring undertakings if other parameters are available from the operator.

Containment assurance and reservoir management shall be reviewed periodically by the operator, and the operator must provide immediate notice to the Director via the offset project developer, and take corrective action if changes occur that have the potential to adversely affect containment, which may include:

- Unexpected changes in project performance that have potential to influence associated storage of CO<sub>2</sub>;
- Addition or abandonment of injection zones;
- Addition or abandonment of injector wells;
- Development of reservoirs which are located above or below the project reservoir;
- Discovery of CO<sub>2</sub> beyond the boundary of the targeted CO<sub>2</sub> geologic storage zone(s); or
- Removal or release of CO<sub>2</sub>.

The D065 CO<sub>2</sub> sequestration scheme approval requires the project operator to develop a closure plan for the sequestration project that specifies criteria for issuance of a closure certificate. The plan should specify:

- The closure process and anticipated timing;
- Monitoring consistent with AER requirements for CO<sub>2</sub> sequestration scheme closure;
- Corrective measures to address potential leakage;
- Provisional plans for site decommissioning, including plans for plugging and abandonment of wells and decommissioning of facilities.

Upon request, the emission offset project developer must provide confirmation that the project continues to operate in accordance with the conditions outlined in the operating license.

These results could be used to provide evidence of containment, including the supporting rationale.

### 5.1.8 Missing Data Procedures

If an emission offset project developer discovers that there is missing data, the procedures for estimating missing data set out in section 17.5.2 of the Alberta Quantification Procedures must be followed with consideration for conservativeness to determine an appropriate substitute for missing data required under the protocol. The project developer must identify the missing data procedure that will be followed in the offset project report and be part of the verification for professional review for reasonableness and conservativeness.

## 5.2 Required Project Documentation

Documentation requirements for the emission offset project are as follows and must be documented in the offset project report:

- The D065 CO<sub>2</sub> sequestration scheme approval number;
- Energy use records for capture, transport and sequestration scheme operations;
- Concentration and measurement records of injected CO<sub>2</sub>;
- A completed Appendix D: **Balance Sheet for Projects Against Physical System Accounting** that includes:
  - The gross quantity of New CO<sub>2</sub> injected into the scheme CO<sub>2</sub>;
  - The project emissions for the current reporting period;
  - The net quantity in tonnes, of CO<sub>2</sub> stored by the project (CO<sub>2</sub> in place);
- Documentation for project eligibility requires at a minimum:
  - The name and contact information of the emission offset project developer(s);
  - Evidence of the CO<sub>2</sub> injection start date;
  - Evidence and explanation of ownership (for each emission offset project);
  - All applicable permits for project condition, where relevant;
  - A suitable monitoring, measurement and verification plan as defined by AER requirements;
  - Evidence that the project results in net geological sequestration located in Alberta including legal land location and GPS coordinates of the site via the inventory; and
  - Project quantification and calculations.
- Documentation for the Baseline condition requires at a minimum:
  - The total emissions for all SSRs included in the baseline;
  - Calculations applied to measured baseline data and justifications for any deviations from those calculations;
  - The measured baseline data for all baseline condition SSRs included in the quantification as recorded from the measurement device before calculations are applied.
- Documentation for the Project condition requires at a minimum:
  - For each project year, the total emissions accounted under each included source/sink;
  - Evidence of timing of project implementation;
  - For each project year, calculations applied to measured project data and justifications for any deviations from required measurements calculations specified in Table 6: **Quantification Methodology**.
  - For each project year, the measured project data as recorded from the measurement device before calculations are applied.
- For projects using 1.4.1 Flexibility Mechanism 1: Direct Air Capture Facility as Emissions Source:
  - Documentation that shows the procurement and voluntary retirement of TIER credit or WREGIS REC (wind or solar);
  - Calculations for balancing imported MWh for the project with the claimed MWh represented by voluntarily retired TIER credit or WREGIS REC. Excess imported MWh must be clearly identified.
  - Documentation supporting the lower carbon intensity factor used for eligible emissions reductions quantification for imported electricity.
    - The environmental attribute voluntarily retired must have emissions reductions estimates (tCO<sub>2</sub>e) balanced against MWh consumed by the project. The appropriate rate of tCO<sub>2</sub>e per MWh must be used.

## 5.3 Record Keeping and Project Archives

Alberta Environment and Protected Areas requires that emission offset project developers retain records as per the requirements in section 31(6) of TIER. Where the emission offset project developer is different from the person implementing the activity or part of the activity, the project developer must maintain sufficient records to support the whole of the offset project. If project ownership changes, sufficient records to support the offset project must be provided to the new owner. The following records must be collected and disclosed to the third-party assurance provider and government third party assurance provider, or Director upon request.

Record keeping requirements include but are not limited to:

- Raw baseline data, independent variable data, and static factors within the measurement boundary;
- A record of all adjustments made to raw baseline data with justification;
- All analysis of baseline data used to create mathematical model(s);
- All data and analysis used to support estimates and factors used for quantification;
- Metering equipment specifications (model number, serial number, manufacturer's calibration procedures/field meter proving method);
- A record of changes in static factors along with all calculations for non-routine adjustments;
- All calculations of greenhouse gas emissions/reductions and where emission factors came from;
- Measurement equipment maintenance activity logs;
- Measurement equipment calibration records or field meter proving records. Flow meters should be maintained and calibrated according to manufacturer specifications and in accordance with the more stringent of the AER Directive 017 requirements and the Quantification Methodologies under Alberta greenhouse gas regulations, and the Specified Gas Reporting Regulation.
- For meters that cannot be calibrated or proved in the field, documentation must be provided by the emission offset project developer or the meter manufacturer to substantiate the use of an alternative meter maintenance program;
- All AER approvals and requirements; and
- All previous verification or reverification records with immaterial findings addressed.

To support the verification, the emission offset project developer must put in place a system that meets or exceeds the following criteria:

- All records must be kept in areas that are easily located;
- All records must be legible, dated and revised as needed;
- All records must be maintained in an orderly manner;
- All documents must be retained in accordance to regulatory requirements;
- Electronic and paper documentation are both satisfactory; and
- Copies of records should be stored to prevent loss of data.
- Attestations are not considered sufficient evidence that an activity took place and do not meet verification requirements.

#### **5.4 Quality Assurance/Quality Control Considerations**

Quality Assurance/Quality Control are applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

- Protecting monitoring equipment (sealed meters and data loggers);
- Protecting records of monitored data (hard copy and/or backup electronic storage);
- Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
- Comparing current estimates with previous estimates as a reality check;
- Providing sufficient training to operators to perform maintenance and calibration of monitoring devices or contract with qualified third parties;
- Establishing minimum experience and requirements for operators in charge of project and monitoring;
- Ensuring that the changes to operational procedures continue to function as planned and achieve net geological sequestration;
- Ensuring that the measurement and calculation system and greenhouse gas reduction reporting remains in place and accurate;
- Checking the validity of all data before it is processed, including emission factors, static factors and acquired data;
- Performing recalculations of quantification procedures to reduce the possibility of mathematical errors;
- Storing the data in its raw form so it can be retrieved for verification;
- Recording and explaining any adjustment made to raw data in the associated report and files; and

- Developing a contingency plan for potential data loss.

## 6.0 References

Alberta Energy Regulator. Directive 007 Volumetric and Infrastructure Requirements. March 27, 2023.

Alberta Energy Regulator. Directive 017 Measurement Requirements for Oil and Gas Operations. March 17, 2022.

Alberta Energy Regulator. Directive 020 Well Abandonment. September 5, 2023.

Alberta Energy Regulator. Directive 051 Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements. April 28, 2023.

Alberta Energy Regulator. Directive 060 Upstream Petroleum Industry Flaring, Incinerating, and Venting. April 6, 2022.

Alberta Energy Regulator. Directive 065 Resources Applications for Oil and Gas Reservoirs. July 27, 2023.

Alberta Environment and Protected Areas. Alberta Emission Offset System Quantification Protocol for Enhanced Oil Recovery Version 2.0. January 2022. |

American Petroleum Institute. International Petroleum Industry Environmental Conservation Association. Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects. Part II: Carbon Capture and Geological Storage Emission Reduction Family. June 2007.

Canadian Standards Association. Z741 Geological Storage of Carbon Dioxide. December 2012.

Det Norske Veritas. CO<sub>2</sub>QUALSTORE Guidelines for Selection and Qualification of Site and Projects for Geological Storage of CO<sub>2</sub>. February 2010.

Government of Alberta. Carbon Offset Emission Factors Handbook.

Government of Alberta. Technical Guidance for the Assessment of Additionality, Version 1.0. May 2018

Government of Alberta. Standard for Greenhouse Gas Emission Offsets Project Developers, Version 3.2. April 2023

International Energy Agency, presentation on Monitoring and Reporting Guidelines for Injection and Storage, January 2014

International Organization for Standardization. ISO 14064-2:2019 Specification with Guidance at the Project Level for Quantification, Monitoring and Reporting of GHG Emission Reductions and Removal Enhancements, 2019

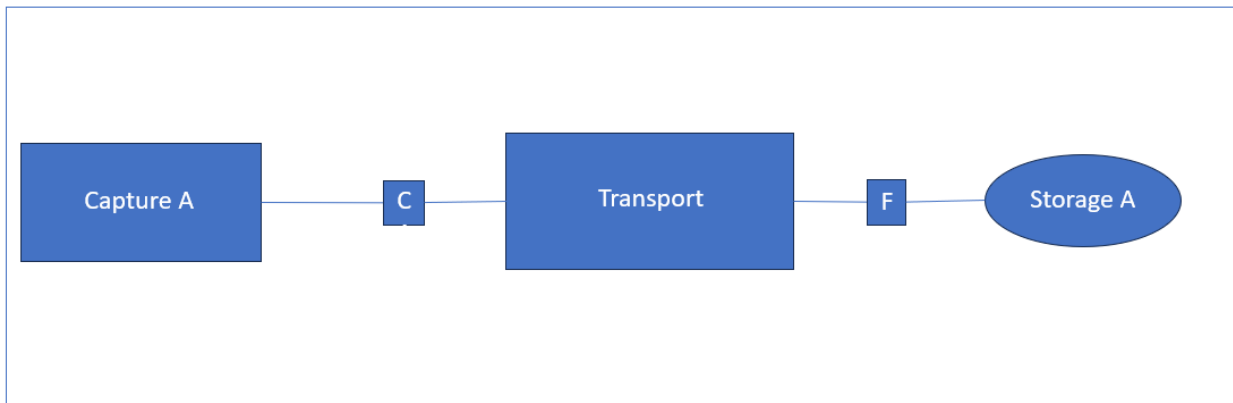
International Organization for Standardization. ISO 27915:2017 Carbon dioxide capture, transportation and geological storage - Quantification and verification, 2017

The United Nations Framework Convention on Climate Change. Implications of the Inclusion of Geological Carbon Dioxide Capture and Storage as CDM Project Activities Draft Final Report - Annex 1, 2009

## Appendix A: CO<sub>2</sub> Injection by Multiple Developers

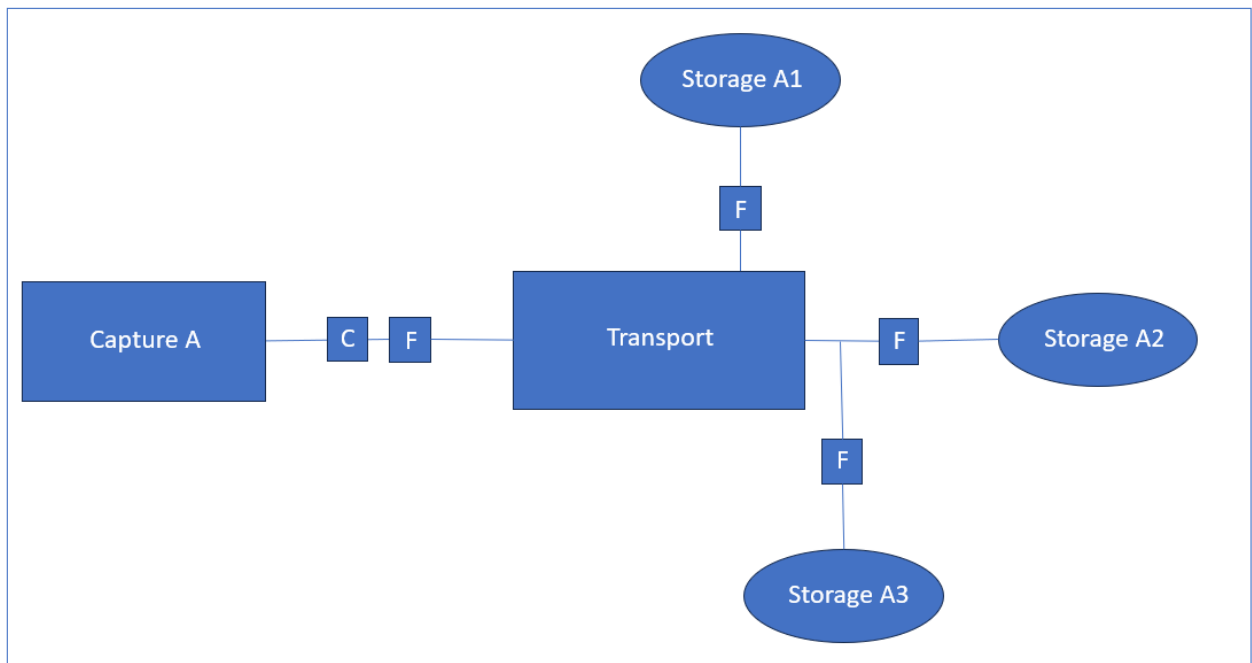
The following provides guidance for projects in which CO<sub>2</sub> is being transported for use in CO<sub>2</sub> sequestration schemes. Gas flow/quantity measurement and CO<sub>2</sub> concentration measurement/sample points must be carefully considered in complex/multiple networks. Scenarios 1 through 4 depict the fluid flow measurement and CO<sub>2</sub> concentration measurement/sample points in a variety of physical network project configurations from simple to more complex.

Scenario 1: Single Capture Single Storage




Must measure CO<sub>2</sub> concentration or gas composition (C). The sample point may be downstream of capture or at the storage location (injection well). Must measure gas quantity (F) at storage location (injection well).

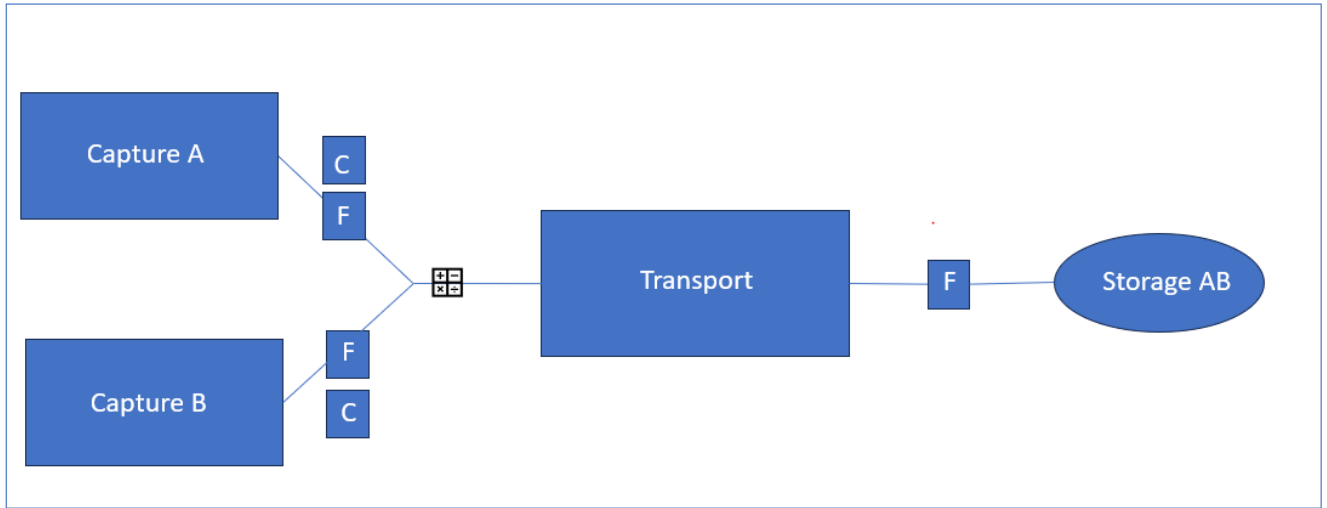
Scenario 2: Single Capture Multiple Storage



Must measure CO<sub>2</sub> concentration or gas composition (C) at either at the point of capture or points of storage. Not required to measure both locations. Must measure gas quantity (F) at the point of storage. Not required to measure gas quantity at inlet of Transport unless gas quantity at each storage location is not available. Must have n-1 measured gas quantities in all cases where n is the number of input and storage points. Measured CO<sub>2</sub> concentration at the inlet to transport will be equal to the CO<sub>2</sub> concentration at storage.

### Scenario 3: Multiple Capture Single Storage


 Indicates concentration calculation based on weighted average of incoming streams

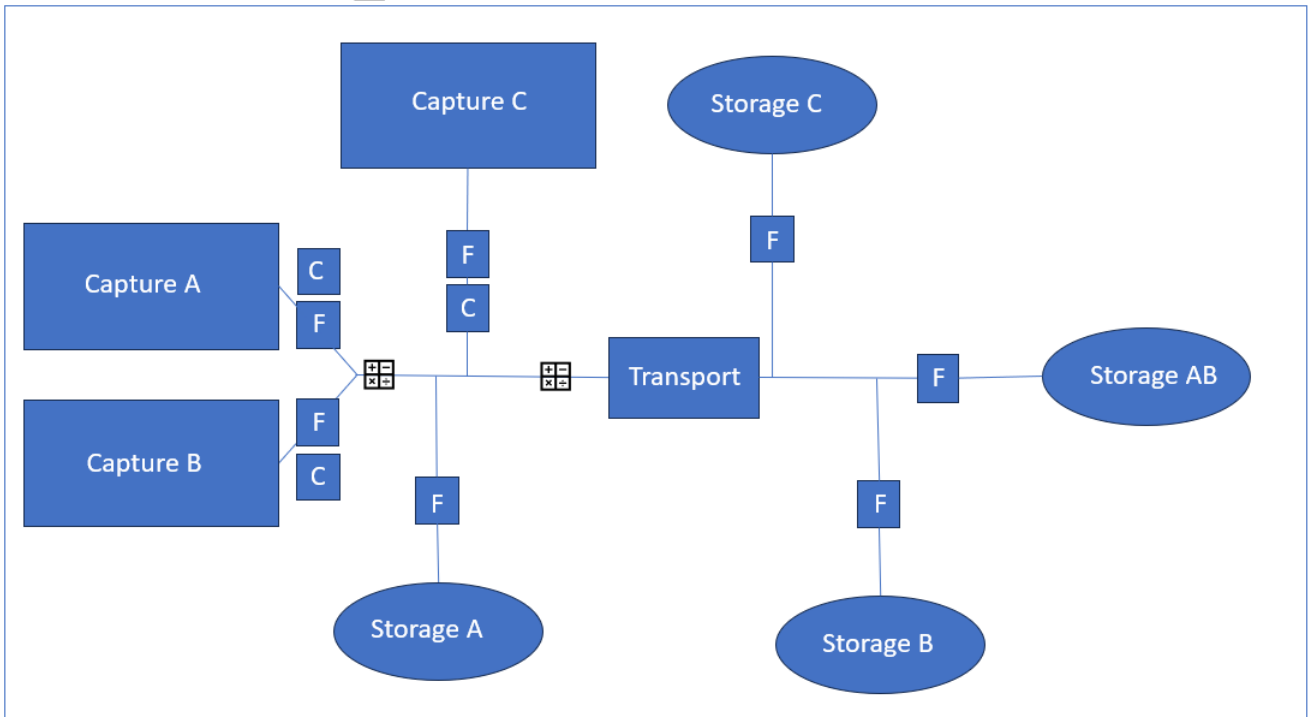


Must measure CO<sub>2</sub> concentration or gas composition at each capture site upstream of comingling. Must measure gas quantity at each capture site upstream of comingling. Allowable to calculate the CO<sub>2</sub> concentration of the comingled stream based on the weighted average of the incoming streams to be comingled in a single variable, mass balance equation.

Must measure gas quantity at storage. The CO<sub>2</sub> concentration at storage is the calculated concentration of the comingled stream. If using a weighted average method, it must be completed downstream of each new capture site that is added to the network.

### Scenario 4: Multiple Capture Multiple Storage

 Indicates concentration calculation based on weighted average of incoming streams



Must measure CO<sub>2</sub> concentration or gas composition at each capture site upstream of comingling. Must measure gas quantity at each capture site upstream of comingling.

Allowable to calculate the CO<sub>2</sub> concentration of the comingled stream based on the weighted average of the incoming streams to be comingled in a single variable, mass balance equation. Weighted average calculation must be completed downstream of each new capture site that is added.

Measure gas quantity at storage. CO<sub>2</sub> concentration at injection is the calculated concentration of the comingled stream or measured upstream of injection. When there is a single unknown, the concentration must be measured at each capture site upstream of where the capture stream comingles.

In addition to careful consideration to sample points and measurement, in complex networks, emission offset project developers must demonstrate that all SSs are properly accounted for and must ensure all emissions have been included and appropriately quantified. For a complex CO<sub>2</sub> system or network, the emissions from that network must be included in the project condition using a system emission factor or a proration of emissions across the network. The emission offset project developers must provide verifiable, reasonable and conservative justification for the method and values used to determine the system emission factor used.

In the multiple capture multiple storage scenarios, details of a full system wide allocation of emissions for each project must be provided for verification/reverification.

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## Appendix B: Guidance for Estimating Emissions from Subsurface Equipment and Targeted Geologic Zone(s)

For the quantification of P20 Emission from Subsurface to Atmosphere, the quantity of emissions leaked from the subsurface equipment or targeted geologic zone(s) to atmosphere for each of the leakage events must be estimated with a maximum overall uncertainty of  $\pm 7.5\%$  over the reporting period using the absolute value of the uncertainty. If the amount of emissions leaked can be estimated within an uncertainty range of  $\pm 7.5\%$ , the estimated figure is reported and used. If the overall uncertainty exceeds  $\pm 7.5\%$ , the following adjustment must be used:

$$\text{CO}_2, \text{ Reported [t CO}_2\text{]} = \text{CO}_2, \text{ Quantified [t CO}_2\text{]} * (1 + (|\text{Uncertainty System [\%]}|/100))$$

Where:

CO<sub>2</sub>, Reported: Amount of CO<sub>2</sub> to be included into the annual emission report with regards to the leakage event in question;

CO<sub>2</sub>, Quantified: Amount of CO<sub>2</sub> determined through the used quantification approach for the leakage even in question; and

Uncertainty System: The level of uncertainty which is associated to the quantification approach used for the leakage event in question.

Adapted from two sources: 1) International Energy Agency presentation on Monitoring and Reporting Guidelines for Injection and Storage<sup>1</sup>; and 2) Clean Development Mechanism United Nations Framework Convention on Climate Change<sup>2</sup>.

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<sup>1</sup> International Energy Agency, presentation on Monitoring and Reporting Guidelines for Injection and Storage, January 2014, which states: "Maximum  $\pm 7.5\%$  uncertainty, if exceeded then add 'uncertainty Adjustment'"

<sup>2</sup> Implications of the Inclusion of Geological Carbon Dioxide Capture and Storage as CDM Project Activities Draft Final Report - Annex 1

Proposed Agenda - Annotations pp 44, Clean Development Mechanism of The United Nations Framework Convention on Climate Change, 2009

# Appendix C: Carbon Capture and Sequestration Containment Assurance Report Template

A completed Containment Assurance Report is required to be submitted by the emission offset project developer to the Director each calendar year, including each year in the post crediting period prior to the issuance of a closure certificate (it is not required to be part of project report submitted to the Registry). The time period and submission date must match the Annual Progress Report submitted to the AER. The AER may also flag any non-compliance events to Alberta Environment and Protected Areas.

TIER sets out that the geological sequestration of carbon dioxide must be permanent to be eligible to generate emission offsets. The purpose of this Containment Assurance Report is to demonstrate that sequestration from a carbon capture and sequestration scheme (and emission offset project) is permanent during the offset crediting period and for the necessary period after the offset crediting period. This report will identify an event that resulted in non-permanent sequestration (i.e. reversal) of the CO<sub>2</sub>.

Reversals are defined in section 1.5 **Reversals**. If the emission offset project developer is not able to provide evidence to demonstrate containment, the project developer must quantify the reversal as set out in section 1.5 **Reversals**.

The emission offset project developer may be a different entity than the sequestration tenure holder, as administered by Energy and Minerals. The containment assurance report should be authored and submitted by the sequestration tenure holder. If there are more than one tenure holders associated with an emission offset project, each tenure holder must submit a containment assurance report.

## **1.0 Project Identification:**

Reporting on Calendar Year:

Offset Project Name and ID:

Crediting Period:

Emission Offset Crediting Period:

Emission Offset Project Developer:

Authorized Project Contact:

Prepared by:

Submission date:

## **2.0 D065 CO<sub>2</sub> Sequestration Scheme Approval Number:**

2.1 Assurance of Containment:

2.2 Mass of CO<sub>2</sub> Injected:

Provide evidence of total CO<sub>2</sub> injected over the last calendar year, including a table with the monthly compositions, volumes, the weighted average composition and quantity injected.

Indicate Directives and data sources from which this evidence is provided.

## **2.3 Conclusion**

The total injected CO<sub>2</sub> for the calendar year 20XX is \_\_\_\_\_ tonnes.

## **2.4 Venting from Injection Well**

Quantification Protocol for Carbon Dioxide Capture and Permanent Geologic Sequestration v2.1

Total vented CO<sub>2</sub> from the injection well in calendar year 20XX is \_\_\_\_\_ tonnes.

### **3.0 Migration of Subsurface CO<sub>2</sub>**

Describe the Permitted Geologic Boundaries and the CO<sub>2</sub> Plume Extent.

Indicate Directives and data sources from which this evidence is provided (for example, Directive 065, Petrinex).

#### **3.1 Conclusion:**

Provide evidence no loss of containment has occurred.

If a loss of containment has occurred provide evidence the loss of containment has been or will be remediated.

If remediation of the loss of containment is not possible, provide evidence of an independent third-party review and determination of volumes of CO<sub>2</sub> expected to reach the atmosphere within 100 years.

#### **4.0 Containment Assurance Conclusion:**

In the calendar year, yyyy/mm/dd – yyyy/mm/dd, covered by this Containment Assurance Report:

There were \_\_\_\_\_ tonnes of New CO<sub>2</sub> injected into the project area.

There were \_\_\_\_\_ tonnes of CO<sub>2</sub> released due to loss of containment.

Signature of designated authority of emission offset project developer:

\_\_\_\_\_

Name:

Title:

Contact email:

Dated:

## Appendix D: Balance Sheet for Projects Against Physical System Accounting

Note physical system could include more than one hub/sequestration location if physically interconnected. Additional projects to be added as needed.

Physical system/hub name:		
Time period:		
Verification date:		
Total CO <sub>2</sub> entering:		tonnes
Total CO <sub>2</sub> injected:		tonnes
Total period emissions:		tonnes
Injected CO <sub>2</sub> originating within the project:		tonnes
Total net electricity import:		MWh
Total net heat import:		GJ
Alberta Emission Offset project name:		
Alberta Emission Offset project ID:		
Time period:		
Verification date:		
Project CO <sub>2</sub> entering:		tonnes
Project CO <sub>2</sub> injected:		tonnes
Total Project emissions:		tonnes
Injected CO <sub>2</sub> originating within the project:		tonnes
Total net electricity import:		MWh
Total net heat import:		GJ
Alberta Emission Offset project name:		
Alberta Emission Offset project ID:		
Time period:		
Verification date:		
Project CO <sub>2</sub> entering:		tonnes
Project CO <sub>2</sub> injected:		tonnes
Total Project emissions:		tonnes
Injected CO <sub>2</sub> originating within the project:		tonnes
Project net electricity import:		MWh
Project net heat import:		GJ
Non-TIER project name:		
System/market:		
Project ID:		
Time period:		
Verification date:		

Project CO <sub>2</sub> entering:		tonnes
Project CO <sub>2</sub> injected:		tonnes
Total Project emissions:		tonnes
Injected CO <sub>2</sub> originating within the project:		tonnes
Project net electricity import:		MWh
Project net heat import:		GJ
Project totals		
Total CO <sub>2</sub> entering:		tonnes
Total CO <sub>2</sub> injected:		tonnes
Total Projects emissions:		tonnes
Injected CO <sub>2</sub> originating within the projects:		tonnes
Total net electricity import:		MWh
Total net heat import:		GJ

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Appendix E: Reversal Error Correction Accounting

				Injection Profile for Sequestration Projects																												Closure Certificate Issued -	38			
Year	1	2	3	4	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	36	37									
DF	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005								
DF- FM3	0.005	0.005	0.005	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01								
Project	FM3?	TIER?	Units																													Closure Certificate Issued -	38			
1	No	Yes	Annual Injected	000 t	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	0	0	0	0	0	0	0			
			Discounted	000 t	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	0	0	0	0	0	0	0		
			Eligible Annual Injected	000 t	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	0	0	0	0	0	0	0		
			Total TIER Reversal Liability	000 t	1000	2000	3000	4000	9000	10000	11000	12000	13000	14000	15000	16000	17000	18000	19000	20000	21000	22000	23000	24000	25000	25000	25000	25000	18000	18000	18000	18000	0	0	0	
2	Yes	Yes	Annual Injected	000 t	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	0	0	0	0	0	0	0			
			Discounted	000 t	5	5	5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0		
			Eligible Annual Injected	000 t	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	0	0	0	0	0	0	0		
			Total TIER Reversal Liability	000 t	1000	2000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	0	0	0
3	No	No	Annual Injected	000 t			0	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	0	0	0	0	0			
			Discounted	000 t			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
			Eligible Annual Injected	000 t			0	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	0	0	0	0	0	0	0
			Total TIER Reversal Liability	000 t			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Yes	Yes	Annual Injected	000 t			0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10		
			Discounted	000 t			0	0	0	0.05	0.05	0.05	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
			Eligible Annual Injected	000 t			0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
			Total TIER Reversal Liability	000 t			0	0	0	0	10	20	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Tonnes Sequestered/Year				000 t	2000	2000	2000	2000	2000	2500	2500	2510	2510	2510	2510	2510	2510	2510	2510	2510	2510	2510	2510	2510	2510	500	500	0	0	0	0	0				
Total Tonnes Sequestered				000 t	2000	4000	6000	8000	18000	20500	23000	25510	28020	30530	33040	35550	38060	40570	43080	45590	48100	50600	53100	55600	58100	58600	59100	59100	41600	41600	41600	41600	41600			
Annual Discount				000 t	10.0	10.0	10.0	15.0	15.0	15.0	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.0	15.0	15.0	15.0	15.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
Total Discount				000 t	10	20	30	45	120	135	150	165	180	195	210	225	240	256	271	286	301	316	331	346	361	361	361	361	361	361	361	361	361	361		
Total Tonnes - Reversal				000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
				Reversal Error Correction Accounting																																
Project	FM3?	LIFO Order	Annual Allocation for Reversal	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1480	2510	2510	2500	2500	2500	2500	500	500								
1	No	1	Allocated Reversal (LIFO)	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1000	1000	1000	1000	1000	1000	1000	0	0	0							
			Volume Subject to Correction	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1000	1000	1000	1000	1000	1000	1000	0	0	0					
2	Yes	2	Allocated Reversal (LIFO)	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	470	1000	1000	1000	1000	1000	1000	1000	0	0	0							
			Volume Subject to Correction	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1000	1000	1000	0	0	0						
3	No	4	Allocated Reversal (LIFO)	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	500	500	500	500	500	500	500	500	500	0							
			Volume Subject to Correction	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					
4	Yes	3	Allocated Reversal (LIFO)	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10	10	0	0	0	0	0	0	0	0	0						
			Volume Subject to Correction	000 t	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	10	10	0	0	0	0	0	0	0	0	0				

**Notes:**

- The example includes four distinct offset projects. Projects 1, 2 and 4 are registered on the Alberta Emission Offset System Registry and serializing emission offsets under the TIER Quantification Protocol for Carbon Dioxide Capture and Permanent Geologic Storage (the protocol). Project 3 is serializing under a voluntary emission offset system, not the Technology, Innovation and Emissions Reduction Regulation (TIER). However, all four projects are injecting into the same injection well.
- Projects 1 and 2 have crediting periods of 25 years (20 years plus one 5 year extension) beginning in Year 1 and ending after Year 25. Projects 3 (under the voluntary system) and 4 have 25 year crediting periods, beginning in Year 3 and ending after Year 27. Crediting periods are shown in the green cells. Post-crediting pre-closure periods are shown in the blue cells.
- Projects 2 and 4 are limiting reversal liability through Flexibility Mechanism 3 (FM3). Projects 1 and 3 are not limiting liability. Discount factors (DF) applied, as described in the protocol, are shown in rows below the project years.
- A 17.5 Mt reversal occurs in year 28. This is the third year of the post-crediting pre-closure period for the Projects 1 and 2, and the first year of the post-crediting pre-closure period for project 4. Details on the treatment of reversal during other project phases can be found in section 1.5 of the protocol.
- In this theoretical example a closure certificate is issued after year 37. This is for illustrative purposes only and does not reflect the likelihood or possibility of closure certificate issuance, particularly after a reversal event. All requirements related to the issuance of a closure certificate must be met by the appropriate tenure holder, and whether or not a closure certificate is issued will be determined by the appropriate regulatory bodies.
- Last-in first-out (LIFO) is applied to determine which serial ranges on the registry are subject to the error correction process. In this example Project 1 was the last to serialize emission offsets on the registry, followed by Project 2, Project 4 and Project 3. For the sake of this example, this LIFO order has remained the same in each year.
- Invalidated serial ranges will follow the invalidation hierarchy under the emission offset error correction process in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports: Cancellation/invalidation will first be applied to emission offsets held by the project developer, followed by emission offsets attributed proportionally to each party holding emission offsets in the affected serial ranges. If the party does not hold sufficient unretired or active emission offsets, remaining cancellation/removal will be attributed proportionally to each facility for each compliance year that the emission offsets were submitted.